

**State of California
Environmental Protection Agency
AIR RESOURCES BOARD**

CALIFORNIA'S LOW CARBON FUEL STANDARD

FINAL STATEMENT OF REASONS

December 2009

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State of California
California Environmental Protection Agency
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**Final Statement of Reasons for Rulemaking,
Including Summary of Public Comments and Agency Responses**

PUBLIC HEARING TO CONSIDER ADOPTION OF A PROPOSED REGULATION TO
IMPLEMENT THE LOW CARBON FUEL STANDARD

Public Hearing Date: April 23, 2009
Agenda Item No.: 09-4-4

I. GENERAL

A. Action Taken in This Rulemaking

In this rulemaking, the Air Resources Board (ARB or the Board) is adopting a new regulation to implement the California Low Carbon Fuel Standard (LCFS). The regulation is a discrete early action measure under the California Global Warming Solutions Act of 2006 (Assembly Bill 32; stats 2006; ch 488) and effectuates Governor Schwarzenegger's Executive Order S-01-07. The regulation will reduce greenhouse gas (GHG) emissions by reducing the carbon intensity of transportation fuels used in California by an average of 10 percent by the year 2020. Carbon intensity is a measure of the GHG emissions associated with the combination of all of the steps in the "lifecycle" of a transportation fuel. This includes the direct GHG emissions associated with the production, transportation, and use of each fuel. For some biofuels, it also includes GHG emissions resulting from land use changes associated with the fuel.

The 10 percent reduction in average carbon intensity is achieved by starting specified providers of transportation fuels (referred to as "regulated parties") at an initial 2011 level and incrementally lowering the allowable carbon intensity for transportation fuels used in California in each subsequent year through 2020. A regulated party's overall carbon intensity for its pool of transportation fuels would then need to meet each year's specified carbon intensity level. Regulated parties can meet these annual carbon intensity levels with any combination of fuels they produce or supply and with LCFS credits generated in previous years or acquired from other regulated parties. There are separate annual carbon intensity standards for gasoline and diesel fuel; the carbon intensity for alternative fuels is judged against either the gasoline or diesel fuel carbon intensity requirements depending on whether the alternative fuel is generally substituting for gasoline or diesel fuel. The regulation includes provisions on exemptions for certain low-carbon fuels, transfers of compliance obligations and regulated party status, calculations of credits and deficits and reconciliation of credit shortfalls, progress reporting and LCFS credit reporting, recordkeeping, evidence of a physical pathway demonstrating that certain reported low-carbon fuels can reasonably

be expected to be used in California, multimedia evaluations, and the periodic review of implementation of the program.

The rulemaking was initiated by the March 5, 2009 publication of a notice for a public hearing scheduled on April 23, 2009. A Staff Report: Initial Statement of Reasons, entitled "Proposed Regulation to Implement the Low Carbon Fuel Standard, Volumes I and II" (Staff Report or ISOR) was also made available for public review and comment starting March 5, 2009. The Staff Report, which is incorporated by reference herein, contains an extensive description of the rationale for the proposal. The originally proposed text of new sections 95480, 95480.1, 95481, 95482, 95483, 95484, 95485, 95486, 95487, 95488, and 95489, title 17, California Code of Regulations, was included as Appendix A to the Staff Report. These documents were also posted on March 5, 2009 on ARB's internet site for this rulemaking at <http://www.arb.ca.gov/regact/2009/lcfs09/lcfs09.htm>. (ARB's Internet Site).

At its meeting on March 16, 2009, the Board received an informational presentation from ARB staff in which the staff discussed the LCFS proposal. The Board made no decisions with respect to the LCFS proposal. Although this was an informational item only, comments (oral and written) from stakeholders were presented to the Board at that meeting. Because the comments were received during the 45-day comment period, those comments are summarized and responded to in this FSOR.

On March 25, 2009, ARB staff published an errata to correct an error, as it appeared in the 45-day notice, in the due date for public comments on the proposed regulatory action.

On April 23, 2009, the Board conducted a public hearing to consider the staff's proposal as set forth in the Staff Report. During the comment period the Board had received 236 separate written comments and multiple copies of six form letters, totaling 2,426 submittals in all. At the hearing the Board received oral testimony from ninety persons and an additional forty-four written statements and other submittals.

At the conclusion of the hearing, the Board adopted Resolution 09-31 (Resolution), in which it approved the originally proposed regulation with a number of modifications. These modifications had been suggested by staff in response to public comments made after issuance of the original proposal. The text or narrative description of each modification was contained in a ten page document entitled, "Public Hearing to Consider Adoption of a Proposed Regulation to Implement the Low Carbon Fuel Standard – Staff's Suggested Modifications to the Original Proposal," which was distributed at the beginning of the hearing and included as Attachment B to the Resolution.

The Resolution directed the Executive Officer to incorporate the modifications described in Attachment B into the originally proposed regulatory text, with such other conforming modifications as may be appropriate. The Executive Officer was directed to make the modified regulation (with the modifications clearly identified) and any additional

documents or information available for a supplemental public comment period of at least 30 days. He was also directed to consider any comments on the modifications received during the supplemental comment period. The Executive Officer was then directed to either (1) adopt the modified regulation as it was made available for public comment, with any appropriate additional nonsubstantial modifications; (2) make additional modifications available for public comment for an additional period of at least 15 days; or (3) present the regulation to the Board for further consideration if he determines that this is warranted.

In preparing the modified regulatory language, the staff made various additional conforming revisions in an effort to best reflect the intent of the Board at the hearing. The staff also identified several additional conforming modifications that are appropriate in order to make the regulation work as effectively as possible. These post-hearing modifications were incorporated into the text of the proposed regulation, along with the modifications specifically identified in Attachment B to the Resolution.

The text of the proposed modifications to the regulation, with the modified text clearly indicated, was made available for a supplemental 30-day comment period ending August 19, 2009 by issuance of a Notice of Public Availability of Modified Text and Supporting Documents and Information (the First Notice of Modified Text). This notice and its two attachments – Resolution 09-31 with attachments and a “Modified Regulation Order” containing the modified regulatory text (the First Modified Text Document) – were posted on July 29, 2009 on the ARB’s Internet site for the rulemaking. Thirty-six written comments were received during the supplemental comment period ending August 19, 2009.

On August 6, 2009, ARB staff published a second errata to correct typographical and table formatting errors in specified information set forth in the First Notice of Modified Text. The errors were located on page 44 of the modified text, Table 7 (Carbon Intensity Lookup Table, section 95486(b)(1)). In Table 7, the “Total” carbon intensity value for “Renewable Diesel (conversion of tallow to renewable diesel)” was erroneously shown as “27.70” in the First Notice of Modified Text; the errata corrected this to “29.70.” The errata also corrected formatting errors in Table 7 consisting of two extra lines; the corrections clarified which rows belonged to the category of “Biodiesel” and which belonged to “Renewable Diesel.”

In light of the supplemental comments received during the 30-day comment period, the Executive Officer determined that additional modifications were appropriate. A Second Notice of Public Availability of Modified Text (the Second Notice of Modified Text) and a “Modified Regulation Order” containing the modified regulatory text (the Second Modified Text Document) were posted September 23, 2009 on the ARB’s Internet site for the rulemaking. The comment period ended October 8, 2009, by which time 19 additional written comments were received.

With respect to each of the two notices of modified text, on the Internet posting date the notices and all attachments were mailed to four parties identified in section 44(a), title 1

CCR, for whom ARB staff did not have electronic mail addresses. At the same time, the notices and all attachments were electronically distributed to all other parties identified in section 44(a), title 1, CCR, in accordance with Government Code section 11340.85, and to all persons that have subscribed to ARB's "LCFS" and "fuels" listserves for notifications of postings pertaining either to rulemaking actions or motor vehicle fuels. The "LCFS" listserve has approximately 6,600 subscribers, and the "fuels" listserve has approximately 5,300 subscribers.

After considering the comments received during the supplemental comment periods, the Executive Officer determined that the regulation was complete and ready for adoption with two limited exceptions. First, it was and is ARB's intent that the regulation identifies carbon intensity values for two additional fuel pathways – biodiesel (fatty acid methyl esters – FAME) converted from Midwest soybeans, and renewable diesel converted from Midwest soybeans. However, by early November 2009 the development of the carbon intensity values had not yet been completed. Second, a severability clause had been inadvertently omitted from the versions of the regulation made available for public comment. The Executive Officer determined it was appropriate to bifurcate adoption of the regulation so that the final regulation except for these two limited incomplete elements will enter into force as expeditiously as possible.

It is ARB's intent that modified regulatory language adding the two incomplete elements will be made available for supplemental comment as soon as possible. Table 7 in section 95486(b) will be augmented by addition of carbon intensity values for the two remaining fuel pathways and insertion of the supporting documentation for the pathways. A new section 95480.1(f) containing severability language similar to that in section 95108, title 17, CCR will also be inserted. After considering comments, the Executive Officer will adopt these two final elements and they will be submitted to the Office of Administrative Law (OAL) along with necessary supporting documents before March 4, 2010.

Accordingly, on November 12, 2009, the Executive Officer issued Executive Order R-09-014, adopting the California LCFS regulation – new sections 95480, 95480.1, 95481, 95482, 95483, 95484, 95485, 95486, 95487, 95488, 95489, and 95490 of title 17, California Code of Regulations – reflecting the final modifications that had been made available for the two supplemental comment periods.¹ The Executive Order expresses ARB's intent that the adopted regulatory language will by the completion of this rulemaking be augmented by the addition of the two remaining elements described above. However, the Executive Officer has determined that the adopted regulation meets all applicable statutory requirements in the absence of those elements.

. Because of the bifurcation, this Final Statement of Reasons (FSOR) includes only comments directed towards the regulation other than the two fuel pathways and severability clause noted above.

¹ The adopted regulatory text contained a few nonsubstantial corrections to the texts made available for the first and second supplemental comment periods.

This Final Statement of Reasons (FSOR) updates the Staff Report by identifying and providing the rationale for the modifications made to the originally proposed regulation. The FSOR also contains a summary of the comments received on the proposed new regulation during the formal regulatory process and ARB's responses to those comments. A separate FSOR document covering the two additional fuel pathways and severability clause referenced above will be issued before March 4, 2009.

B. Incorporation of Materials by Reference

The definitions in section 95481 of the regulation incorporate by reference five Standard Specifications or Standard Practices issued by ASTM International, formerly known as the American Society for Testing and Materials (ASTM). Sections 95481(a)(8) and 95487(b)(2) incorporate by reference two guidance documents. Sections 95486(b)(1) and 95486(c)(3) incorporate two computer models: (1) the California-modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model ("CA-GREET"), version 1.8b, February 2009, and (2) the Global Trade Analysis Project (GTAP) Model (February 2009), which is a software package comprised of RunGTAP (February 2009), a visual interface for use with the GTAP databases (posted at <http://www.arb.ca.gov/fuels/lcfs/lcfs.htm> in February 2009 and available for download at <https://www.gtap.agecon.purdue.edu/products/rungtap/default.asp>); GTAP-BIO (February 2009), the GTAP model customized for corn ethanol (posted at <http://www.arb.ca.gov/fuels/lcfs/lcfs.htm> in February 2009 and available with its components as a .zip file for download at <http://www.arb.ca.gov/fuels/lcfs/gtapbio.zip>); and GTP-SGR (February 2009), the GTAP model customized for sugarcane ethanol (posted at <http://www.arb.ca.gov/fuels/lcfs/lcfs.htm> in February 2009 and available with its components as a .zip file for download at <http://www.arb.ca.gov/fuels/lcfs/gtapsgr.zip>). Section 95486(b)(1)(A) incorporates 16 fuel pathway supporting documents prepared by ARB's Stationary Source Division.

Each instance of incorporation identifies the incorporated document or model by title and date. All of the documents and models were made available in the context of this rulemaking in the manner specified in Government Code section 11346.5(b) or 11347.1. The five referenced ASTM documents are published by ASTM International, a well-established and prominent organization in the standards-setting and analysis field. Section 95487(b)(2) identifies the ARB website location where the Cal/EPA Guidance Document can be downloaded. Section 95486(b)(1) identifies the ARB website location where the CA-GREET and GTAP models may be downloaded. It should be noted that fully functional, working versions of both the CA-GREET model and GTAP model package were installed on a laptop and made available for public review at ARB's principal place of business in Sacramento, California, during the 45-day comment period. The sixteen fuel pathway documents and the Guidebook referenced in section 95481(a)(8) are readily available from ARB's internet site and upon request. Based on the above reasons, these documents are reasonably available to the affected public from commonly known sources.

These documents are referenced and incorporated into the California Code of Regulations because it would be cumbersome, unduly expensive, and otherwise impractical to publish them in the Code. Existing ARB administrative practice has been to have specifications, test procedures, and similar documents incorporated by reference rather than printed in the CCR because these specifications and procedures are highly technical and complex. These include “nuts and bolts” engineering protocols and laboratory practices and have a very limited audience. Because ARB has never printed complete test procedures and similar documents in the CCR, the directly affected public is accustomed to the incorporation format used in the regulation. These test procedures and similar documents as a whole are extensive, and it would be both cumbersome and expensive to print these lengthy, technically complex procedures in the CCR for a limited audience. Printing portions of the test procedures and other documents that are incorporated by reference would be unnecessarily confusing to the affected public. For similar reasons, it has been a longstanding and accepted practice of the ARB to incorporate ASTM International standards and test methods into the CCR by reference. (see, e.g., section 2263, title 13, CCR.) Among other things, this enables interested parties to verify that the standards or practices have been adopted by a consensus-driven, authoritative source. It is not technically possible to publish computer models such as CA-GREET and GTAP in the CCR. And, due to their length and limited audiences, it is impractical to publish the two referenced guidance documents and the sixteen ARB fuel pathway documents in the CCR.

C. Fiscal Impacts

Pursuant to Government Code section 11346.9(a)(2), the Executive Officer determined that the regulatory action will not impose a mandate on any local agency or school district, whether or not reimbursable by the state pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code.

D. Consideration of Alternatives

Four regulatory alternatives were analyzed in the ISOR. In the ISOR, the Board considered four different approaches to the regulation, which are summarized below:

- Only implement the federal renewable fuels program;
- Implement a gasoline standard only;
- Delay LCFS Pending Possible National Regulation; and
- Delay LCFS Pending Development of Regional GHG Programs.

The ARB considered these four potential alternative approaches to the regulation and found that none was more effective in carrying out the purpose of the proposed regulation, or would be as effective and less burdensome than the proposed regulation. The responses to comments section below addresses additional alternatives proposed by commenters during the rulemaking progress.

1. Implement Only the Federal RFS2

The U.S EPA has adopted its Renewable Fuel Standard (RFS2) regulation – title 40, Code of Federal Regulations (CFR), part 80, section 1100 et seq. – that mandates the blending of specific volumes of renewable fuels into gasoline and diesel sold in the U.S. each year. As defined, “renewable fuels” under the RFS2 superficially resembles the list of liquid transportation fuels subject to the LCFS. However, there are a number of reasons why the RFS2 is not comparable to the LCFS.

Congress adopted a renewable fuels standard in 2005 and strengthened it in December 2007 as part of the Energy Independence and Security Act (EISA). The RFS2 requires that 36 billion gallons of biofuels be sold annually by 2022, of which 21 billion gallons must be “advanced” biofuels and the other 15 billion gallons can be corn ethanol. The advanced biofuels are required to achieve at least 50 percent reduction from baseline lifecycle GHG emissions, with a subcategory required to meet a 60 percent reduction target. These reduction targets are based on lifecycle emissions, including emissions from land use changes.

Although the RFS2 is a step in the right direction, the RFS2 volumetric mandate alone will not achieve the objectives of the LCFS. The RFS2 targets only biofuels and not other alternatives; therefore, the potential value of electricity, hydrogen, and natural gas are not considered in an overall program to reduce the carbon intensity of transportation fuels. In addition, the targets of 50 percent and 60 percent GHG reductions only establish the minimum requirements for biofuels. It forces biofuels into a small number of fixed categories and thereby stifles innovation. Finally, it exempts existing and planned corn ethanol production plants from the GHG requirements, thus providing no incentive for reducing the carbon intensity from these fuels.

By contrast, the LCFS regulates all transportation fuels, including biofuels and non-biofuels, with a few narrow and specific exceptions. Thus, non-biofuels, such as compressed natural gas, electricity, and hydrogen, play important roles in the LCFS program. In addition, the LCFS encourages much greater innovation than the federal program by providing important incentives to continuously improve the carbon intensity of biofuels and to deploy other fuels with very low carbon intensities.

If California were to rely solely on the RFS2 (i.e., the “No LCFS” alternative), the State would not achieve the GHG emission reductions called for in AB 32 Scoping Plan and Executive Order S-01-07. The RFS2, by itself, achieves only approximately 30 percent of the GHG reductions projected under the LCFS program. Additional details on this analysis are presented in Chapter VI of the ISOR.

Further, as discussed in Chapter VIII of the ISOR, the marginal cost of meeting LCFS requirements instead of RFS2 mandates is related to the amount of advanced and cellulosic ethanol used in California’s transportation fuels in lieu of corn-based ethanol that would be imported into the State under RFS2. Staff estimates that, when cellulosic ethanol production is proven on a commercial scale, it will be more cost-effective than

corn-based ethanol; therefore, under the most conservative assumption, the LCFS will not increase costs relative to RFS2. With significantly more GHG emission reductions, the proposed LCFS is preferred over the RFS-only alternative.

2. Implement a Gasoline Standard Only

The LCFS includes two separate standards for gasoline and the alternative fuels that can replace it, and for diesel fuel and its replacements. A gasoline standard only approach has been advocated by various stakeholders to allow for a simpler implementation of the regulation in the early years. The Board considered this alternative and determined it was not appropriate for various reasons.

First, a comprehensive approach from the beginning of the LCFS program will allow for the development of a more robust credit market and will provide greater certainty on future expectations. Fuel producers will need to consider overall approaches to providing low carbon transportation fuels. Given the fact that the compliance requirements are substantially less in the early years should provide fuel producers adequate time to develop appropriate compliance options.

Second, because diesel accounts for approximately 20 percent of the total liquid transportation pool of California, failure to include diesel will result in a loss of approximately 20 percent of the LCFS benefits. Therefore, this alternative would not meet the requirements of AB 32.

Third, from the three illustrative diesel scenarios presented in the Chapter VIII of the ISOR, the Board estimated that with the tax incentives in place, lower-CI alternative diesel fuels result in an overall savings relative to the base case of strictly petroleum-based fuels. Excluding diesel from the LCFS will not only forgo 20 percent of the GHG emission reductions from the proposal, but will also forgo possible overall savings to the State.

3. Delay LCFS Pending Possible National Regulation

In taking positive steps toward reducing GHG emissions, the Board believes that California should not simply defer to the federal government. Deferring to the federal government would conflict with the requirements of AB 32 and Executive Order S-01-07. As such, ARB is without authority to simply defer to the federal government.

Moreover, the implementation of successful state-level programs can hasten the development of similar programs by other states, and, ultimately, by the federal government. Similarly, a single successful national program based on California's efforts can stimulate the development of related programs in other nations. In this respect, California seeks to implement an LCFS that will accelerate the adoption of similar measures nationally and possibly even internationally.

Even if ARB were to defer to the federal government, doing so would not ensure that effective action at the federal level would be taken in the near future to meet the requirements of AB 32. The U.S. EPA has not specified a timeframe by which it would develop a national LCFS-type regulation. Therefore, deferring to the federal government's efforts to develop a national LCFS program would be unacceptably open-ended.

4. Delay LCFS Pending Development of Regional GHG Programs

One potential regulatory alternative would be to delay the LCFS regulation pending development of regional GHG programs, like the one under development by the Western Climate Initiative (WCI). In the Western Climate Initiative Design Recommendations document, the Partners recommended the WCI include direct emissions from gasoline and diesel combusted as transportation fuel. They also recommended that direct CO₂ emissions from the combustion of pure biofuels be excluded from the cap-and-trade program. ARB staff believes it is critical to include full fuel-lifecycle GHG emissions and to address both fossil fuels and biofuels. Therefore, California is moving forward with the development of the LCFS. We recognize that combined state, national, and international efforts are necessary to solve the global warming crisis. We will continue to coordinate our work with the states and Canadian provinces in the Western Climate Initiative (WCI). We appreciate their efforts to reduce greenhouse gases, and we will work with the WCI partners in their future efforts to assess whether and how to include upstream emissions associated with bio and fossil fuels prior to the start of the cap and trade program.

At the time the Board approved the LCFS, it was the Board's understanding that the WCI was awaiting California's development before the WCI establishes its regional regulation. Because of this, delaying the LCFS development while the WCI's efforts were pending would have made little sense. Therefore, staff deemed this alternative as infeasible.

II. MODIFICATIONS MADE TO THE ORIGINAL PROPOSAL

The following discussion addresses all substantive modifications made to the originally proposed regulatory text. It does not include modifications to correct typographical and citation errors, numbering errors, grammar errors, or the rearranging of sections and paragraphs for structural improvements, nor does it include all of the minor revisions made to improve clarity.

A. Regulation Review (Section 95489)

Originally proposed section 95489 directed ARB's Executive Officer to conduct a review of the implementation of the LCFS program by January 1, 2012, providing that the Executive Officer was to determine the scope and content of the review. A number of commenters urged the Board to substantially expand this requirement by mandating more than one review, identifying specific items that are to be addressed in the reviews, and providing for one or more advisory panels. The commenters asserted that the trailblazing nature of the LCFS program justified these steps. In response to these comments and as suggested by staff at the hearing, the Board made major revisions to the review provisions.

First, the Board added a second review and expressly provided that the Executive Officer's reviews are to be presented to the Board. The first review is to be completed and presented to the Board by January 1, 2012, and the second review is to be completed and presented to the Board by January 1, 2015. The Executive Officer is directed to conduct the two reviews in a public process and to conduct at least two workshops prior to presenting the reviews to the Board. In presenting the reviews, the Executive Officer is to propose any amendments or such other action he or she determines are warranted.

Second, the Board's modifications identify 13 specific areas that are at a minimum to be considered in the review. These areas are:

- (1) The LCFS program's progress against LCFS targets;
- (2) Adjustments to the compliance schedule, if needed;
- (3) Advances in full, fuel-lifecycle assessments;
- (4) Advances in fuels and production technologies, including the feasibility and cost-effectiveness of such advances;
- (5) The availability and use of ultralow carbon fuels to achieve the LCFS standards and advisability of establishing additional mechanisms to incentivize higher volumes of these fuels to be used;
- (6) An assessment of supply availabilities and the rates of commercialization of fuels and vehicles;
- (7) The LCFS program's impact on the State's fuel supplies;
- (8) The LCFS program's impact on state revenues, consumers, and economic growth;

- (9) An analysis of the public health impacts of the LCFS at the state and local level, including the impacts of local infrastructure or fuel production facilities in place or under development to deliver low carbon fuels, using an ARB approved method of analysis developed in consultation with public health experts from academia and other government agencies;
- (10) An assessment of the air quality impacts on California associated with the implementation of the LCFS; whether the use of the fuel in the State will affect progress towards achieving State or federal air quality standards, or results in any significant changes in toxic air contaminant emissions; and recommendations for mitigation to address adverse air quality impacts identified;
- (11) Identification of hurdles or barriers (e.g., permitting issues, infrastructure adequacy, research funds) and recommendations for addressing such hurdles or barriers;
- (12) Significant economic issues; fuel adequacy, reliability, and supply issues; and environmental issues that have arisen; and
- (13) The advisability of harmonizing with international, federal, regional, and state LCFS and lifecycle assessments.

Third, the modifications direct the Executive Officer to establish an LCFS advisory panel by July 1, 2010. Panel participants should include representatives of the California Energy Commission, the California Public Utilities Commission, fuel providers, storage and distribution infrastructure owner/operators, consumers, engine and vehicle manufacturers, environmental justice organizations, environmental groups, academia, public health, and other stakeholders and government agencies as deemed appropriate by the Executive Officer. The advisory panel is to participate in the required reviews of the LCFS program, and the Executive Officer is directed to solicit comments and evaluations from the panel on the ARB staff's assessments of the 13 review areas described above, as well as on other topics relevant to the periodic reviews.

All of these modifications are appropriate to assure that all significant potential issues that may arise during implementation of the LCFS program are analyzed and addressed in a transparent process that draws upon the expertise of interested parties.

B. Identification of Carbon Intensity Values (Section 95486)

1. Identification of Carbon Intensity Values Under the Original Proposal

As noted above, carbon intensity is a measure of the direct and indirect GHG emissions associated with each of the steps in the full fuel cycle of a transportation fuel (also referred to as the "well-to-wheels" for fossil fuels, or "seed or field-to-wheels" for biofuels). Depending on the circumstances, GHG emissions from each step can include carbon dioxide (CO₂), methane, nitrous oxide (N₂O), and other GHG contributors. Moreover, the overall GHG contribution from each particular step is a function of the energy that the step requires. Under the regulation, carbon intensity is accordingly

expressed in terms of grams of CO₂ equivalent per mega-Joule (gCO₂e/MJ). Since compliance with the LCFS is determined by comparing the carbon intensity for particular California transportation fuels with the maximum required carbon intensity level for gasoline or diesel fuel for each year starting in 2011, the regulation needs to assign carbon intensity values for transportation fuels produced and distributed through significantly different “fuel pathways,” or identify mechanisms for determining the values.

The regulation provides that the carbon intensity of a fuel is determined in two parts. The first part represents all of the direct emissions associated with producing, transporting, and using the fuel. This involves determining the amount of GHG emissions emitted per unit of energy for each of the steps in the fuel pathway. The second part considers other effects, including those caused by changes in land use. For some crop-based biofuels, staff has identified land use changes as a significant source of additional GHG emissions. Therefore, staff proposed that emissions associated with land use changes be included in the carbon intensity values assigned to those fuels in the regulation. No other significant effects that result in large GHG emissions were identified that would substantially affect the LCFS framework for reducing the carbon intensity of transportation fuels.

To assess the direct emissions, staff used a modified version of the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model. Argonne National Laboratories developed the original GREET model. The modified model, referred to as CA-GREET, was developed under contract with the California Energy Commission. Staff used the CA-GREET model as the primary method for calculating carbon intensity values for various transportation fuels.

CA-GREET is essentially a very large spreadsheet that incorporates many specific numeric values that allow for the calculation of the lifecycle GHG emissions associated with producing, transporting, and using various fuels. Staff used CA-GREET to develop specific carbon intensities for a number of different pathways. For some fuels, multiple pathways were developed that represent differences in how and where the fuel is produced.

To assess the emissions from land use changes, staff used the Global Trade Analysis Project (GTAP) to estimate the GHG emissions impact. The GTAP model is discussed in the Staff Report and related Appendices. In general, the model evaluates the worldwide land use conversion associated with the production of crops for fuel production. Different types of land use have different rates of storing carbon. In general, multiplying the changes in land use times an emission factor per land conversion type yields an estimate of the GHG emissions impacts of land conversions.

The regulation establishes three different methods for establishing carbon intensities. In Method 1, a Lookup Table identifies carbon intensity values for a number of specified fuel pathways. Regulated parties may choose to use these pathways (if applicable) to calculate credits and deficits. Under the original proposal, the Lookup Table with its carbon intensity values was not contained in the regulation itself. Instead, upon

adoption of the LCFS regulation, the Executive Officer was directed to certify Method 1 carbon intensity values for various fuels and fuel pathways; these carbon intensity values would then be published in a Lookup Table to be used by regulated parties. Tables IV-20 and IV-21 of the Staff Report set forth the fuel and fuel pathway carbon intensity values identified by staff to date, using the CA-GREET model for direct effects and the GTAP model when applicable for indirect effects. Staff initially proposed that, at the hearing, the Board approve the carbon intensity values in Tables IV-20 and IV-21 of the Staff Report. It was anticipated that the initial Method 1 carbon intensity values certified by the Executive Officer would be based on the Board-approved values with modifications reflecting any updated information and any new fuel pathways for which sufficient data had been developed by the time of certification. Under the original proposal, the Executive Officer could subsequently certify new carbon intensity values or modifications to the Lookup Table values at his or her own initiative.

Under the other two methods – Methods 2A and 2B – a regulated party could apply for Executive Officer certification of a modified or new pathway or new pathway. Method 2A covered proposed modifications to inputs already incorporated in CA-GREET, to reflect the conditions specific to the regulated party's production and distribution process. Method 2B covered the generation of a proposed new fuel pathway, using the CA-GREET model and, if indirect effects are involved, GTAP or an equivalent model. For both Method 2A and 2B, there was a scientific defensibility requirement for the regulated party to meet before the Executive Officer can approve new values. For Method 2A, there was an additional provision that requires a substantial change in the carbon intensity relative to the analogous value calculated for that pathway under Method 1.

Note that while the carbon intensity values for the various fuels and fuel pathways reflect the amount of GHG emissions per unit of energy, they do not reflect the fact that some fuels and vehicles are more energy efficient than others. More energy-efficient fuels and vehicles will travel more miles per unit of energy input to the vehicle, thus resulting in less fuel consumption and CO₂ emissions. For example, the well-to-wheel CO₂ emissions from electric vehicles, in units of gCO₂e/MJ of energy delivered to the vehicle, are generally higher than for gasoline vehicles; this results in a higher carbon intensity value for electricity. However, electric vehicles require much less energy to travel a specified distance. As a result of their much lower per mile energy consumption, electric vehicles emit less GHGs than gasoline vehicles on a per mile basis, even though they emit more per unit of energy consumed. In order to account for this phenomenon, the credits generated for a particular fuel reflect an adjustment for the "energy economy ratio" (EER) of the fuel relative to gasoline (for fuels used in light- and medium-duty vehicles) or diesel fuel (for fuels used in heavy-duty and off-road applications). Thus, for passenger cars, the EER for gasoline is 1.0 while the EER of electricity used in a battery electric or plug-in hybrid electric vehicle is 3.0.

have the effect of establishing an important element of the regulation without following the rule-adoption process or applying robust criteria in the regulation that significantly narrow the Executive Officer's discretion in certifying carbon intensity values. This could result in disapproval of the mechanism by the Office of Administrative Law (OAL); OAL reviews regulations adopted by California state agencies before they become effective. Concerns had also been raised that, as initially proposed, the certification process might not be sufficiently transparent.

Accordingly, with respect to Method 1, the Board modified section 95486(b) to make the Lookup Table and its carbon intensity values part of the regulation. While the carbon intensity values in the Lookup Table can only be amended or expanded by regulatory amendments, in Resolution 09-31 the Board delegated to the Executive Officer the responsibility to conduct the necessary rulemaking hearings and take final action on any amendments, other than amending indirect land-use change values included in the Lookup Table as adopted in this LCFS rulemaking. This is appropriate because of the technical nature of the carbon intensity determinations and the need to expedite the amendment process.

Set forth below are the two Lookup Tables included in section 95486(b) as adopted. They are expanded versions of Tables IV-20 and IV-21 in the Staff Report. Both tables were added to the regulation and modified in response to comments received during the two supplement comment periods pursuant to the Board's directive in Resolution 09-31. Under the Board's direction, several pathways were added relative to the original tables shown in the Staff Report:

- 2 pathways for biodiesel (fatty acid methyl esters – FAME) converted from waste oils;
- 2 pathways for renewable diesel converted from tallow;
- 5 pathways for producing liquefied natural gas (LNG) from North American sourced natural gas (NG); overseas NG with regasification & reliquefaction; overseas NG without regasification & reliquefaction; landfill biogas; and dairy digester gas;
- 1 pathway for compressed natural gas produced from dairy digester gas; and
- 3 pathways for producing ethanol from Brazilian sugarcane (average; average+electricity co-product; average+electricity co-product+mechanized harvesting).

To facilitate a comparison to the carbon intensity values recommended in the Staff Report, additions released in the First Notice of Modified Text are shown in underline and deletions are shown in ~~strikeout~~, and additions released in the Second Notice of Modified Text are shown in double underline and deletions are shown in ~~double strikethrough~~.²

² The two lookup tables as shown in the Final Regulation Order are presented in plain text because the entire LCFS regulation (17 CCR section 95480 et seq.) represents new language.

Table 6. Carbon Intensity Lookup Table for Gasoline and Fuels that Substitute for Gasoline

<u>Fuel</u>	<u>Pathway Description</u>	<u>Carbon Intensity Values</u> <u>(gCO₂e/MJ)</u>		
		<u>Direct Emissions</u>	<u>Land Use or Other Indirect Effect</u>	<u>Total</u>
<u>Gasoline</u>	<u>CARBOB – based on the average crude oil delivered to California refineries and average California refinery efficiencies</u>	<u>95.86</u>	<u>0</u>	<u>95.86</u>
<u>Ethanol from Corn</u>	<u>Midwest average; 80% Dry Mill; 20% Wet Mill; Dry DGS</u>	<u>69.40</u>	<u>30</u>	<u>99.40</u>
	<u>California average; 80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG</u>	<u>65.66</u>	<u>30</u>	<u>95.66</u>
	<u>California; Dry Mill; Wet DGS; NG</u>	<u>50.70</u>	<u>30</u>	<u>80.70</u>
	<u>Midwest; Dry Mill; Dry DGS, NG</u>	<u>68.40</u>	<u>30</u>	<u>98.40</u>
	<u>Midwest; Wet Mill, 60% NG, 40% coal</u>	<u>75.10</u>	<u>30</u>	<u>105.10</u>
	<u>Midwest; Wet Mill, 100% NG</u>	<u>64.52</u>	<u>30</u>	<u>94.52</u>
	<u>Midwest; Wet Mill, 100% coal</u>	<u>90.99</u>	<u>30</u>	<u>120.99</u>
	<u>Midwest; Dry Mill; Wet, DGS</u>	<u>60.10</u>	<u>30</u>	<u>90.10</u>
	<u>California; Dry Mill; Dry DGS, NG</u>	<u>58.90</u>	<u>30</u>	<u>88.90</u>
	<u>Midwest; Dry Mill; Dry DGS; 80% NG; 20% Biomass</u>	<u>63.60</u>	<u>30</u>	<u>93.60</u>
	<u>Midwest; Dry Mill; Wet DGS; 80% NG; 20% Biomass</u>	<u>56.80</u>	<u>30</u>	<u>86.80</u>
	<u>California; Dry Mill; Dry DGS; 80% NG; 20% Biomass</u>	<u>54.20</u>	<u>30</u>	<u>84.20</u>
	<u>California; Dry Mill; Wet DGS; 80% NG; 20% Biomass</u>	<u>47.404</u>	<u>30</u>	<u>77.404</u>
	<u>Brazilian sugarcane using average production processes</u>	<u>27.40</u>	<u>46</u>	<u>73.40</u>
<u>Ethanol from Sugarcane</u>	<u>Brazilian sugarcane with average production process, mechanized harvesting and electricity co-product credit</u>	<u>12.240</u>	<u>46</u>	<u>58.240</u>
	<u>Brazilian sugarcane with average production process and electricity co-product credit</u>	<u>20.40</u>	<u>46</u>	<u>66.40</u>

<u>Compressed Natural Gas</u>	<u>California NG via pipeline; compressed in CA</u>	<u>67.70</u>	<u>0</u>	<u>67.70</u>
	<u>North American NG delivered via pipeline; compressed in CA</u>	<u>68.00</u>	<u>0</u>	<u>68.00</u>
	<u>Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in CA</u>	<u>11.26</u>	<u>0</u>	<u>11.26</u>
	<u>Dairy Digester Biogas to CNG</u>	<u>13.45</u>	<u>0</u>	<u>13.45</u>
<u>Liquefied Natural Gas</u>	<u>North American NG delivered via pipeline; liquefied in CA using liquefaction with 80% efficiency</u>	<u>83.13</u>	<u>0</u>	<u>83.13</u>
	<u>North American NG delivered via pipeline; liquefied in CA using liquefaction with 90% efficiency</u>	<u>72.38</u>	<u>0</u>	<u>72.38</u>
	<u>Overseas-sourced LNG delivered as LNG to Baja; re-gasified then re-liquefied in CA using liquefaction with 80% efficiency</u>	<u>93.37</u>	<u>0</u>	<u>93.37</u>
	<u>Overseas-sourced LNG delivered as LNG to CA; re-gasified then re-liquefied in CA using liquefaction with 90% efficiency</u>	<u>82.62</u>	<u>0</u>	<u>82.62</u>
	<u>Overseas-sourced LNG delivered as LNG to CA; no re-gasification or re-liquefaction in CA</u>	<u>77.50</u>	<u>0</u>	<u>77.50</u>
	<u>Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 80% efficiency</u>	<u>26.31</u> <u>05</u>	<u>0</u>	<u>26.31</u> <u>05</u>
	<u>Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 90% efficiency</u>	<u>15.56</u>	<u>0</u>	<u>15.56</u>
	<u>Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 80% efficiency</u>	<u>28.53</u> <u>27</u>	<u>0</u>	<u>28.53</u> <u>27</u>
	<u>Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 90% efficiency</u>	<u>17.78</u>	<u>0</u>	<u>17.78</u>
<u>Electricity</u>	<u>California average electricity mix</u>	<u>124.10</u>	<u>0</u>	<u>124.10</u>
	<u>California marginal electricity mix of natural gas and renewable energy sources</u>	<u>104.7</u> <u>01</u>	<u>0</u>	<u>104.7</u> <u>01</u>
<u>Hydrogen</u>	<u>Compressed H₂ from central reforming of NG (includes liquefaction and re-gasification steps)</u>	<u>142.0</u> <u>20</u>	<u>0</u>	<u>142.0</u> <u>20</u>
	<u>Liquid H₂ from central reforming of NG</u>	<u>133.00</u>	<u>0</u>	<u>133.00</u>
	<u>Compressed H₂ from central reforming of NG (no liquefaction and re-gasification steps)</u>	<u>98.80</u>	<u>0</u>	<u>98.80</u>
	<u>Compressed H₂ from on-site reforming of NG</u>	<u>98.30</u>	<u>0</u>	<u>98.30</u>
	<u>Compressed H₂ from on-site reforming with renewable feedstocks</u>	<u>76.10</u>	<u>0</u>	<u>76.10</u>

Table 7. Carbon Intensity Lookup Table for Diesel and Fuels that Substitute for Diesel

<u>Fuel</u>	<u>Pathway Description</u>	<u>Carbon Intensity Values</u> <u>(gCO₂e/MJ)</u>		
		<u>Direct Emissions</u>	<u>Land Use or Other Indirect Effect</u>	<u>Total</u>
<u>Diesel</u>	<u>ULSD – based on the average crude oil delivered to California refineries and average California refinery efficiencies</u>	<u>94.71</u>	<u>0</u>	<u>94.71</u>
<u>Biodiesel</u>	<u>Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME) where “cooking” is required</u>	<u>13.70</u> <u>15.84</u>	<u>0</u>	<u>13.70</u> <u>15.84</u>
	<u>Conversion of waste oils (Used Cooking Oil) to biodiesel (fatty acid methyl esters -FAME) where “cooking” is not required</u>	<u>11.76</u>	<u>0</u>	<u>11.76</u>
<u>Renewable Diesel</u>	<u>Conversion of tallow to renewable diesel using higher energy use for rendering</u>	<u>29.70</u> <u>39.33</u>	<u>0</u>	<u>29.70</u> <u>39.33</u>
	<u>Conversion of tallow to renewable diesel using lower energy use for rendering</u>	<u>19.65</u>	<u>0</u>	<u>19.65</u>
<u>Compressed Natural Gas</u>	<u>California NG via pipeline; compressed in CA</u>	<u>67.70</u>	<u>0</u>	<u>67.70</u>
	<u>North American NG delivered via pipeline; compressed in CA</u>	<u>68.00</u>	<u>0</u>	<u>68.00</u>
	<u>Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in CA</u>	<u>11.26</u>	<u>0</u>	<u>11.26</u>
	<u>Dairy Digester Biogas to CNG</u>	<u>13.45</u>	<u>0</u>	<u>13.45</u>
<u>Liquefied Natural Gas</u>	<u>North American NG delivered via pipeline; liquefied in CA using liquefaction with 80% efficiency</u>	<u>83.13</u>	<u>0</u>	<u>83.13</u>
	<u>North American NG delivered via pipeline; liquefied in CA using liquefaction with 90% efficiency</u>	<u>72.38</u>	<u>0</u>	<u>72.38</u>
	<u>Overseas-sourced LNG delivered as LNG to Baja; re-gasified then re-liquefied in CA using liquefaction with 80% efficiency</u>	<u>93.37</u>	<u>0</u>	<u>93.37</u>
	<u>Overseas-sourced LNG delivered as LNG to CA; re-gasified then re-liquefied in CA using liquefaction with 90% efficiency</u>	<u>82.62</u>	<u>0</u>	<u>82.62</u>
	<u>Overseas-sourced LNG delivered as LNG to CA; no re-gasification or re-liquefaction in CA</u>	<u>77.50</u>	<u>0</u>	<u>77.50</u>

	<u>Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 80% efficiency</u>	<u>26.3105</u>	<u>0</u>	<u>26.3105</u>
	<u>Landfill Gas (bio-methane) to LNG liquefied in CA using liquefaction with 90% efficiency</u>	<u>15.56</u>	<u>0</u>	<u>15.56</u>
	<u>Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 80% efficiency</u>	<u>28.5327</u>	<u>0</u>	<u>28.5327</u>
	<u>Dairy Digester Biogas to LNG liquefied in CA using liquefaction with 90% efficiency</u>	<u>17.78</u>	<u>0</u>	<u>17.78</u>
<u>Electricity</u>	<u>California average electricity mix</u>	<u>124.10</u>	<u>0</u>	<u>124.10</u>
	<u>California marginal electricity mix of natural gas and renewable energy sources</u>	<u>104.701</u>	<u>0</u>	<u>104.701</u>
<u>Hydrogen</u>	<u>Compressed H₂ from central reforming of NG (includes liquefaction and re-gasification steps)</u>	<u>142.020</u>	<u>0</u>	<u>142.020</u>
	<u>Liquid H₂ from central reforming of NG</u>	<u>133.00</u>	<u>0</u>	<u>133.00</u>
	<u>Compressed H₂ from central reforming of NG (no liquefaction and re-gasification steps)</u>	<u>98.80</u>	<u>0</u>	<u>98.80</u>
	<u>Compressed H₂ from on-site reforming of NG</u>	<u>98.30</u>	<u>0</u>	<u>98.30</u>
	<u>Compressed H₂ from on-site reforming with renewable feedstocks</u>	<u>76.10</u>	<u>0</u>	<u>76.10</u>

As noted previously, it is ARB's intent that, by the end of the rulemaking, Table 7 in section 95486(b) will include specified carbon intensity values and supporting documentation for two additional fuel pathways. These fuel pathways are for biodiesel (fatty acid methyl esters – FAME) converted from Midwest soybeans, and for renewable diesel converted from Midwest soybeans. Those two pathways will be discussed in a separate FSOR, as noted before.

Another modification provides that the carbon intensity values in the Lookup Tables for the fuel pathways shown in Tables 6 and 7 are described in the sixteen supporting ARB fuel pathway documents that are incorporated by reference in section 95486(b)(1)(A) through (P); this clarifies the specific parameters covered by each of the listed pathways.

With respect to Methods 2A and 2B, the considerations precluding at this time a certification system for the Executive Officer's determination of CI values at his own initiative similarly preclude a certification system for acting on requests from regulated parties under these other two methods. However, the Method 2A and 2B mechanisms provide appropriate criteria for determining the circumstances in which the regulation will be amended to provide customized Lookup Table values or new pathways in response to regulated party requests. Inclusion of these methods will also give regulated parties advance notice of the necessary documentation, so that the Executive Officer can conduct and complete the rule-amendment process as expeditiously as

possible. Methods 2A and 2B have accordingly been retained, with appropriate modifications, to identify when a regulated party request will trigger an Executive Officer rulemaking on customized Lookup Table values or new pathways. Modifications have been made to the regulatory text relating to the public review process in Methods 2A and 2B to make it consistent with the rulemaking process set forth in the Administrative Procedure Act.

In connection with the Second Notice of Modified Text, staff clarified the language in section 95486(a) (Selection of Method) by adding a provision that makes it clear a regulated party's choice of carbon intensity value picked from the Lookup Table is subject to Executive Officer approval. The prior language was ambiguous as to what happens if the Executive Officer disagrees with the regulated party's choice of carbon intensity value. In cases where the Executive Officer has reason to believe the regulated party did not choose the most closely-corresponding carbon intensity value, the Executive Officer is directed to assign the carbon intensity value from the Lookup Table that the Executive Officer determines is the value that most closely corresponds to the regulated party's fuel or blendstock pathway. If the Executive Officer chooses to assign a more appropriate carbon-intensity value, he/she is directed to provide the rationale for the decision to the regulated party within 10 business days, and he/she may consider any information submitted by the regulated party in support of its choice of carbon intensity value.

2. Carbon Intensity for CARBOB and Diesel Fuel

The regulation contains specific regulatory provisions for determining the carbon intensity for diesel fuel and "CARBOB" – the blendstock to which ethanol is added to produce finished California gasoline. The Method 1 lookup table sets forth single total CARBOB and diesel fuel carbon intensity values covering crude production, refining, use of the fuel, and all transportation and distribution activities. The carbon intensity values are based on the average crude oil delivered to California refineries in 2006, and the average California refinery efficiencies in 2006 (2006 was the last year for which data were available). As shown in the tables set forth above, the Method 1 total carbon intensities are 95.86 gCO₂e/MJ for California CARBOB and 94.71 gCO₂e/MJ for California diesel fuel. The portion of the total average carbon intensity values that is attributable to the average carbon intensity of producing and transporting the crude oil for California CARBOB and diesel fuel is 6.93 gCO₂e/MJ.

With the exception described below, regulated parties must use these single carbon intensity values for all California CARBOB and diesel fuel regardless of the actual carbon intensity of producing or transporting the specific crude oil used, or the specific refinery operations. This approach is taken to reduce the incentive for regulated parties to comply with the LCFS by shifting to less carbon-intensive crude oils or refinery operations. Use of less carbon intensive crude oils would likely do nothing to reduce global GHG emissions because the higher carbon-intensive crude oils replaced would be refined and used elsewhere. California refineries and large oil extraction operations will be subject to the upcoming AB 32 cap and trade program, so any reductions in

GHG emissions from these activities will be counted in that program. The objective of the LCFS program is to stimulate more fundamental changes to the transportation fuel pool, moving towards fuels that meet the much lower carbon intensities needed to meet long-term GHG emissions goals. This objective is best served by identifying single carbon intensity values for almost all CARBOB and diesel fuel, and not allowing revised pathways to be established under Method 2A for CARBOB and diesel fuel with lower carbon intensities.

The Method 1 default carbon intensity values apply to all CARBOB and diesel fuel produced from crude oil that made up 2.0 percent or more of the 2006 California baseline crude mix by volume as shown in California Energy Commission records (“included in the 2006 California baseline crude mix”). The default Method 1 values also apply to CARBOB and diesel fuel produced from any other crudes except high carbon-intensity crude oils (HCICOs) – those for which the total crude production and transport carbon intensity value is greater than 15.00 gCO₂e/MJ. This threshold differentiates lower carbon intensity primary and secondary production from higher carbon intensity fuel production. Examples of HCICOs include certain crude oils produced from oil sands, oil shale, or through thermal enhanced oil recovery processes.

The two percent threshold is designed to differentiate established crude sources that made up a significant fraction of the California crude oil supply in 2006 from potential emerging crude sources that could be a significant part of the crude supply in the future and could significantly increase the overall average carbon intensity attributable to crude oil. The two percent threshold brings in more than 95 percent of the total California crude supply in 2006; it is appropriate to provide for additional consideration of the potential carbon intensity effects from the remaining potential emerging crude sources.

For CARBOB and diesel fuel made from any HCICO that was not included in the 2006 California baseline crude mix, the regulated party could not initially use the otherwise-applicable Lookup Table value based on average carbon intensity values. Instead, the regulated party would have to use Method 2B to generate an additional pathway for this type of crude oil (alternatively, a previously approved pathway could be used if it is applicable to the crude oil in question). If Method 2B shows that the carbon intensity for crude production and transport has been reduced to no more than 15.00 gCO₂e/MJ – through technologies such as carbon capture and sequestration – the CARBOB or diesel fuel resulting from such crude production would qualify for the default carbon intensity values based on overall averages. Otherwise, the actual carbon intensity from production and transport of the crude would have to be used.

The HCICO that qualifies for the default average carbon intensity values under Method 1 is California crude oil produced using TEOR. The estimated carbon intensity from production and transportation of this crude oil is 18.89 gCO₂e/MJ. Because the production facilities are situated in California, they will be subject to the AB 32 cap and trade program that is scheduled to start in 2012. We expect that the cap and trade program will result in either application of technologies at the production facilities that

reduce the carbon intensity below 15.00 gCO₂e/MJ, or the acquisition of credits from other GHG emission reduction activities that achieve the equivalent to such a reduction in carbon intensity. The California cap and trade program will not apply to out-of-state HCICO production facilities, although there is a possibility it could be part of a broader regional program under the WCI. However, if those out-of-state facilities demonstrate equivalent reductions, they will be able to bring themselves under the 15.00 gCO₂e/MJ threshold level and become subject to the same average carbon intensity values as apply to the volumes of HCICO produced in California.

At this time, HCICO produced from oil sands is most likely to come to California from Canadian producers. However, current projections of imports from Canada strongly suggest that such HCICO is not likely to be imported to or processed by refineries in California for a number of years. According to the Energy Information Administration (EIA), total crude imports to the United States from Canada were 716 million barrels in 2008. For the same year, the total crude imports to the western states, (PADD 5) the Pacific Northwest, from Canada were 55 million barrels. According to the California Energy Commission (CEC), 644 million barrels of crude were processed by California refineries in 2008. This is about 90 percent of the total Canadian exports to the U.S. Without significant increases in crude oil production for export, crude oil from Canada is not available for export in significant volumes to California.

While this increase in production is possible, it will not take place for several years. The total volume currently supplied to the West Coast (assuming it is all supplied to California) would only be about 8 percent of the demand. Because this is already accounted for, supplying California will require new production wells and new processing infrastructure. In addition, pipeline capacity needs to be increased to get the crude to the Pacific Northwest for shipping to California. The most efficient way would be to build a pipeline to California, but that would take about five years. In summary, significant imports to California from Canada are at least several years away.

Post-hearing modifications have added language that would require regulated parties for gasoline, CARBOB, or diesel fuel derived from HCICO to calculate deficits relative to the carbon intensity standards in sections 95482 separately for the HCICO and non-HCICO feedstocks (section 95486(b)(2)(A)2); these modifications are necessary to assure the credit calculations accurately reflect the use of HCICO. In connection with the Second Notice of Modified Text, staff further modified the language governing the deficit treatment of CARBOB, gasoline or diesel fuel derived from HCICO. The modifications specify the regulated party must perform a calculation for the base deficit (treating the entire volume of fuel as if it were average CARBOB (for gasoline) or average California diesel (for diesel fuel) and using the average carbon intensity values from the Lookup Tables accordingly) and a separate calculation for the incremental deficit. The incremental deficit would charge the volume derived wholly from HCICO with the actual carbon intensity for that HCICO (determined using the specified procedure). As noted previously, the initial regulated party (i.e., the transferor) would retain the obligation to account for the incremental deficits incurred from the HCICO, while the recipient would get the obligation to account for the base deficits (unless the

parties agree otherwise by written contract; modifications to section 95484, “Regulated Parties” provide for such an agreement).

C. Demonstration of Physical Pathways (section 95484(d)(2))

Section 95484(d)(2) as originally proposed prohibited a regulated party from generating credits from a fuel unless the party has demonstrated or provided a sufficiently detailed demonstration of the delivery methods comprising the physical pathway for each of the regulated party’s fuels to the fuel blender, producer, importer, or provider in California. The demonstration must be approved by the Executive Officer. Pursuant to Resolution 09-31, a modification allows demonstrations by fuel producers who are not regulated parties, such as an out-of-state ethanol producer that does not itself import ethanol into California. This will permit a regulated party to meet at least part of its physical pathway requirements by citing approved pathway demonstrations submitted by non-regulated party fuel producers whose fuels are used by the regulated party. (section 95484(d)(2).)

Post-hearing modifications made for the first and second supplemental comment periods address the effects a material change or non-material change would have to an approved physical pathway and when such changes have to be reported to the Executive Officer. (formerly section 95484(d)(2)(D), renumbered to 95484(d)(2)(F)). Originally, “material change” had been broadly defined as any change other than a change in the name, phone number, mailing address, or company name of person covered by physical pathway documentation. Where there was a material change to an approved physical pathway demonstration, the regulated party was required to apply for a new approval of a new demonstration reflecting the material change. For changes that were not material, the regulated party was required to notify the Executive Officer within 10 days of the change.

The final definition of “material change” has been modified to narrow its focus significantly; as modified, a “material change” to an approved physical pathway would include only those changes that involve a change in the basic mode of transportation for the fuel (e.g., if shipping or trucking replaces any leg in an approved pathway that formerly included only transport by rail). The regulated party for a pathway with a material change must report the change within 30 business days, and the approval will become invalid 30 business days after the change. To be able to generate credits after the approved pathway becomes invalid, the regulated party will need to apply for a new approval. These modifications should provide ample time for regulated parties to report the change while providing time for ARB staff to flag such a change in the online quarterly reporting. Notification of nonmaterial changes is no longer required.

Additional modifications to final section 95484(d)(2)(G)1 clarify that LCFS credits based on an approved pathway can be claimed retroactively no earlier than January 1, 2011. Since there is no applicable LCFS standard before 2011, there should be no generation of credits before 2011.

The regulation initially defined “physical pathway” as the applicable combination of actual fuel delivery methods that a regulated party expects the fuel to be transported under contract from the fuel producer to the California blender, producer, importer, or provider. (section 95484(d)(2).) This was revised in the second set of modifications so that it refers to the combination of methods that a regulated party “reasonably” expects. The party should not be able to rely on an expectation that is not reasonable.

In Resolution 09-31, the Board agreed with staff’s recommendation of a modification providing that ARB’s website list the non-regulated parties with approved demonstrations of physical pathways. In order to make the website information as useful as possible, the final modifications add a provision requiring the Executive Officer to post on the ARB website the names and contact information for each regulated party and non-regulated party fuel producer that has obtained approval for their physical pathways, as well as the transportation fuels subject to such approved physical pathways. (new section 95484(d)(5)). The second set of modifications added a requirement that the website listing also include details of each approved physical pathway, subject to the requirements of the California Public Records Act and ARB’s regulations governing the treatment of confidential information. This will enhance the ability of a regulated party to rely on another party’s approved physical pathway demonstration, and inform all parties of the sorts of pathways that have been approved.

D. Reporting Requirements (section 95484(c))

As originally proposed, section 95484(c)(3)(C)1. (“Specific Quarterly Reporting Requirements for Electricity”) would have required the electricity delivered to residential charging stations and used for transportation purposes to be reported based on direct metering. Commenters indicated that, given the utilities’ planned phase-in of “smart” meters that would accomplish this goal in a few years, it could be unnecessarily burdensome to require direct metering in the early years of the LCFS program. They recommended that the objective can be accomplished with alternative methods that are equivalent to direct metering. The staff agreed and suggested that the regulatory language be modified to provide modified the reporting requirements for residential charging stations have been modified to permit alternative reporting methods that are shown to the Executive Officer to be substantially similar to direct metering (also called “submetering”). This alternative reporting will be allowed prior to January 1, 2015, but only for those households and residences in which direct metering has not been installed; effective January 1, 2015, regulated parties will need to use direct metering to report the amount of electricity sold for transportation purposes at all residential charging stations if the regulated party chooses to generate credits. (section 95484(c)(3)(C)1.).

As originally proposed, section 95486(c)(3)(A)1. required quarterly reports from regulated parties to include the product transfer documents from transfers of fuel that could affect the identity of the regulated party for the fuel. A requirement for the automatic submittal of these documents is not needed and could be onerous. Accordingly, a modification identified in the Second Notice of Modified text provides that

submittal of these documents is only required within 10 business days of a request by the Executive Officer. This is sufficient to enable enforcement staff to monitor compliance.

Original section 95486(c)(3)(A)3. required that a regulated party's quarterly report to include the volume of each blendstock per compliance period. Another modification identified in the Second Notice of Modified Text allows the reported volumes of blendstocks to be aggregated for each distinct carbon intensity value, since the separate volumes are treated differently for compliance purposes. This modification also added a requirement for reporting the total energy of a fuel derived from HCICO. This is necessary for consistency with and to help implement the provisions added to clarify the deficit calculations for HCICO-derived fuels that were added to section 95486(b)(2)(A)2.

E. Enforcement Protocols (new section 95490)

A new section 95490 has been added allowing the Executive Officer to enter into an enforceable written protocol with a regulated party or other person to identify conditions under which the party may comply with the recordkeeping, reporting, and demonstration of physical pathway requirements in the LCFS program under mechanisms equivalent to those specified in the regulation. This will allow the accommodation of circumstances particular to the party while still requiring compliance with the regulatory requirements. Similar provisions have worked effectively in ARB's regulations establishing specifications for gasoline and diesel fuel (e.g. title 13, CCR, secs. 2270(a)(5) and 2282(f)(5).)

F. LCFS Credits and Deficits (section 95485(c))

A post-hearing modification clarifies that the prohibition on purchases, sales, and trades of LCFS credits by a third party entity that is not a regulated party or acting on behalf of a regulated party does not apply when the regulated party that owns the credits is exporting such credits for compliance with other greenhouse gas reduction initiatives. (section 95485(c)(1)(B)). Otherwise, section 95485(c)(1)(C) provisions authorizing export of credits could be ineffectual. There are grammatical edits to the language in section 95485(c) for clarity.

G. Applicability (section 95480.1(a) and (d))

In the originally proposed regulation, the section 95482(b) and (c) tables showing the 2011-2020 compliance schedules for gasoline, diesel fuel, and their substitutes identified the 2010 requirements as "Reporting Only." To more clearly effectuate the original intent, a post-hearing modification added language to section 95480.1(a) stating that the reporting and recordkeeping requirements and violations provision of the LCFS (sections 95484(c), (d) and (e) respectively) apply starting on January 1, 2010, and the remaining provisions of the LCFS regulation apply starting on January 1, 2011.

Under the original proposal, the regulation did not apply to transportation fuel used in military tactical vehicles as defined in title 13, CCR, section 1905(a). In response to comments from the U.S. Navy, the exemption was expanded to include transportation fuel used in tactical support equipment as defined in title 17, CCR, section 93116.2(a)(36). Tactical vehicles and tactical equipment share a common fuel consistent with deployment requirements and training realism.

H. Definitions (section 95481)

The definition of “biogas” has been modified to provide a more accurate description of how biogas is produced and cite a few examples of the processes and source materials used to produce biogas. (section 95481(a)(5)). A definition for “liquefied petroleum gas (LPG or propane)” has been added because it was not previously defined in the initially proposed regulatory text. (section 95481(a)(30)). In a post-hearing modification, the definitions for “oil sands” and “oil shale” were deleted because those terms are not used in the regulation as adopted. (formerly section 95481(a)(34) and (35)).

III. SUMMARY OF COMMENTS MADE DURING THE 45-DAY COMMENT PERIOD AND AGENCY RESPONSES

This Section III. contains a summary of each comment that (1) was submitted at the hearing or during the 45-day comment period and (2) was specifically directed at the proposed regulation or to the procedures followed by ARB in proposing or adopting regulation, together with ARB's responses. Comments not involving objections or recommendations specifically directed towards the regulation or procedures followed are generally not summarized. These include comments supporting the LCFS proposal and "Citizens" who applauded the enormous task of regulating GHGs from the transportation sector.

Several environmental groups including the American Lung Association of California, Sierra Club of California, Union of Concerned Scientists, NRDC, Environmental Defense Fund, Environmental Coalition, and Friends of the Earth, supported most elements of the proposal, particularly including indirect effects of changes in land use patterns caused by crop-based biofuels. In addition, the American Bakers Association, American Beverage Association, American Frozen Food Institute, Grocery Manufacturers Association, and the Snack Food Association also agreed with our inclusion of land use change effects in the carbon intensity calculations of biofuels.

Alternative fuel providers, such as CalETC, PG&E, Clean Energy, and Waste Management, also agreed with elements of the regulation, including incentives built into the regulation that will increase the use of their lower carbon intensity fuels. They were also supportive of the regulation providing an even playing field in the transportation fuel section. While biofuel companies disagreed with the inclusion of land use change effects when calculating the carbon intensity of biofuels, most acknowledged the importance of the LCFS and stated that they strongly supported the concept of an LCFS.

Several out-of-state groups, such as NESCAUM (Northeast States for Coordinated Air Use Management) and the Oregon Environmental Council, submitted generally supportive comments, expressing the belief that the LCFS was a good framework or starting point for their state governments to begin adoption of an LCFS. The ARB staff has been working closely with both Oregon and NESCAUM on their developing programs.

A. LIST OF COMMENTERS

The table below identifies the comments received during the 45-day comment period that presented an objection or recommendation specifically directed towards the regulation or the procedures followed. The table provides a correlation between (1) the abbreviation used in this Section III to refer to a comment letter or testimony; and (2) the name of the person(s) signing the comment letter or presenting the testimony. Written submittals were received between March 5, 2009 and April 23, 2009. Oral testimony was presented either at the April 23, 2009 hearing or at the March 19, 2009 informational presentation to the Board.

Comment Abbreviation	Commenter
111SCIENTISTS	111 Scientists. Letter submitted by Simmons Blake Written testimony: March 2, 2009
179SCIENTISTS	179 Scientists. Letter submitted by Patricia Monahan, Union of Concerned Scientists Written testimony: April 21, 2009
A2O4NESTE1	Cal Hodge, A2O Inc. on behalf of Neste Oil Written testimony: April 18, 2009
A2O4NESTE2	Cal Hodge, A2O Inc. on behalf of Neste Oil Written testimony: April 22, 2009
AAM	Ellen Shapiro, Alliance of Automobile Manufacturers Written testimony: April 22, 2009
AB32IMPG1	Dorothy Rothrock, California Manufacturers and Technology Association; Amisha Patel, California Chamber of Commerce; Julie Sauls, California Trucking Association; David A. Bischel, California Forestry Association; Robert Neenan, California League of Food Processors; Rex Hime, California Business Properties Association; Tom Holsman, Associated General Contractors of California; Rodney Pierini, California Automotive Wholesalers Association; Carolyn Casavan, West Coast Environmental and Engineering; Stuart Waldman, Valley Industry & Commerce Association; Betty Jo Toccoli, California Small Business Association; Bill La Marr, California Small Business Alliance; Jan Marie Ennenga, Manufacturers Council of the Central Valley; Gerry Bonetto, Printing Industries of California; Kris Hunt; Contra Costa Taxpayers Association, Jay McKeeman; California Independent Oil Marketers Association, James F. Simonelli; California Metals Coalition; Patti Krebs, Industrial Environmental Association; Scott Anderson, Industrial Assn. of Contra Costa County; Willie Galvan, American GI Forum of California; Catherine H. Reheis-Boyd, Western States Petroleum Association; Veronica Perez Becker, Central City Association of Los Angeles

	<p>Bill Dombrowski, California Retailers Association; Frank J. De Smidt, Milpitas Chamber of Commerce; Shelly Sullivan, AB 32 Implementation Group</p> <p>Written testimony: March 30, 2009</p>
AB32IMPG2	<p>Shelly Sullivan*; Jeanne Cain, California Chamber of Commerce; Dorothy Rothrock, California Manufacturers & Technology Association; Matthew Hargrove, California Business Properties Association; Julie Sauls, California Trucking Association; Bill Dombrowski, California Retailers Association; Jay McKeeman, California Independent Oil Marketers Association; Justin Oldfield, California Cattlemen's Association; Rich Matteis, California Farm Bureau Federation; Ed Yates, California League of Food Processors; Kelly McKechnie, Western Growers Association; Steve Brink, California Forestry Association; Keri Askew Bailey, California Grocers Association</p> <p>Written testimony: April 20, 2009</p>
ABCINC	<p>Robert Kozak, Atlantic Biomass Conversions, Inc.</p> <p>Written testimony: April 21, 2009</p>
ABCON	<p>Jamie Knapp*; Kathy Andria, American Bottom Conservancy; Bonnie Holmes-Gen, American Lung Association in California; Dan Taylor, Audubon California; Andy Katz, MCP Breathe California; Warner Chabot, California League of Conservation Voters; Steve Kozel, Sr., Calumet Project; Bessie Dent, Calumet Project; Brian Nowicki, Center for Biological Diversity; John Shears, Center for Energy Efficiency and Renewable Technologies; Lynn Thorp, Clean Water Action; Peter J. Taglia, Clean Wisconsin; Shankar Prasad, Coalition for Clean Air; Michael Marx, Corporate Ethics International; Bruce Baizel, EARTHWORKS; Charles Griffith, Ecology Center; Remy Garderet, Energy Independence Now; Timothy Telleen-Lawton, Environment America; Caitlyn Toombs, Environment California; Scott Graecen, Environmental Protection and Information Center; Kari Hamerschlag, Environmental Working Group; Aaron Sange, ForestEthics; Michael Noble, Fresh Energy; Danielle Fugere, Friends of the Earth</p> <p>Written testimony: April 15, 2009</p>
ABENGOA	<p>Christopher Standlee*, Abengoa Bioenergy; BioEnergy International, LLC; BlueFire Ethanol Fuels, Inc.; California Ethanol & Power, LLC; Ceres, Inc.; Coskata Iogen Corporation; Novozymes; Pacific Ethanol; Qteros, Inc.; Verenium; ZeaChem Inc.</p> <p>Written testimony: April 15, 2009</p>
ABFA	<p>Michael McAdams, Advanced Biofuels Association</p> <p>Written testimony: April 22, 2009</p>

ABUSA	Ivanc, Joanne, Advanced Biofuels USA Written testimony: March 20, 2009
ACE	Brian Jennings, American Coalition for Ethanol Written testimony: April 21, 2009
ADM	Dean Frommelt, Archer Daniels Midland Written testimony: December 16, 2009
AE1	Christopher J. Holly, Alberta Energy Written testimony: April 23, 2009
AE2	Christopher J. Holly, Alberta Energy Oral testimony: April 23, 2009
AFBF	Bob Stallman, The American Farm Bureau Federation Written testimony: March 25, 2009
AGBC	Thor Bailey, Ag Biomass Council Inc. Written testimony: March 24, 2009
AIR	Tom Frantz, Association of Irrigated Residents Written testimony: April 21, 2009
AIRE	Tom Darlington, Air Improvement Resource Oral testimony: April 23, 2009
ALA1	Bonnie Holmes-Gen, American Lung Association in California Written testimony: March 25, 2009
ALA2	Will Barrett, American Lung Association in California; Dave Modisette, California Electric Transportation Coalition; John Shears, Center for Energy Efficiency and Renewable Technologies; Tim Carmichael, Coalition for Clean Air; Daniel Emmett, Energy Independence Now; Danielle Fugere, Friends of the Earth; Roland Hwang; Natural Resources Defense Council; Saul Zambrano, Pacific Gas and Electric Company; Michael J. Gianunzio, Sacramento Municipal Utility District; William Zobel, San Diego Gas & Electric Company; Michael M. Hertel, Southern California Edison Company; Patricia Monahan, Union of Concerned Scientists Written testimony: April 14, 2009
ALA3	Jenny Bard* and Bonnie Holmes-Gen, American Lung Association in California; Eva K. Lean, American Cancer Society; Andy Katz, Breathe California; Martin Martinez, California Pan-Ethnic Health Network; Bonnie Castillo, California Nurses Association; David Claman, California Thoracic Society; Jeanne Rizzo, Breast Cancer Fund; Gerardo Gomez, Long Beach Alliance for Children with Asthma; Kevin Hamilton; Medical Advocates for Healthy Air (Fresno); Robert Gould, Physicians for Social Responsibility, San Francisco Bay Area Chapter; Jeremy Cantor, Prevention Institute; Robin Salsburg, Public Health Law & Policy; Mary Pittman, Public Health Institute; Al Lerma, Sonoma County Asthma Coalition; Anne Kelsey-Lamb, Regional Asthma

	Management and Prevention Written testimony: April 22, 2009
ALA4	Bonnie Holmes-Gen., American Lung Association in California Oral testimony: March 26, 2009
ALA5	Bonnie Holmes-Gen., American Lung Association in California Oral testimony: April 23, 2009
ALEX1	Charles Alexander (Ref: Food_vs_Fuel_Analysis) Written testimony: April 7, 2009
ALEX2	Charles Alexander (Ref: External GHG Credits) Written testimony: April 7, 2009
APCINC	William Farone, Applied Power Concepts, Inc. Written testimony: March 22, 2009
ARCURE	Barbara Arcure Written testimony: April 2, 2009
ATA	Richard Moskowitz, American Trucking Associations Written testimony: April 22, 2009
BAAQMD	Jack Broadbent, Bay Area AQMD Written testimony: April 21, 2009
BAMCGRP	Jamie Knapp*; Fedele Bauccio, Bon Appétit Management Company; Lisa Bicker, CleanTECH San Diego; Dr. Bob Epstein & Nicole Lederer, Environmental Entrepreneurs; Robert J. Fisher, Gap, Inc.; Scott Hauge, Small Business California; Elliot Hoffman, New Voice of Business; Jim Macias, Fulcrum Bioenergy, Inc.; Jim McDermott, US Renewables Group; Anthony Minite, Bentley Prince Street, Inc.; Tom Unterman, Rustic Canyon Partners; Steve Westly, The Westly Group; Azita Yazdani, Exergy Systems, Inc.; Paul S. Zorner, Hawai'i BioEnergy, LLC Written testimony: April 20, 2009
BAYBIO	Matthew M. Gardner, BayBio Written testimony: April 22, 2009
BCC1	Bill Holmberg, Biomass Coordinating Council Written testimony: March 19, 2009
BCC2	Bill Holmberg, Biomass Coordinating Council Written testimony: April 17, 2009
BELLIZI	Chris Bellizzi Written testimony: April 20, 2009
BERG	Peter Berg Written testimony: March 20, 2009
BI	Russell Teall, Bio-diesel Industries Oral testimony: April 23, 2009
BIO	Brent Erickson, Biotechnology Industry Organization Written testimony: April 22, 2009
BP1	Ralph Moran, BP America

	Written testimony: April 21, 2009
BP2	Ralph Moran, BP America Oral testimony: April 23, 2009
BPLACE1	Sven Thesen* and Jason Wolf, Better Place Written testimony: April 22, 2009
BPLACE 2	Sven Thesen, Better Place Oral testimony: April 23, 2009
BRENNAN	John Brennan Written testimony: April 8, 2009
BS	Joel Velasco, Brazilian Sugarcane Oral testimony: April 23, 2009
BSCSC	Liz Kniss, County of Santa Clara Board of Supervisors Written testimony: April 17, 2009
BURR	Jason Burr Written testimony: April 18, 2009
CACA1	Tom Talbot, CA Cattlemen's Association; Doug Masebar, CA Farm Bureau Federation; Karen Ross, CA Association of Winegrape Growers; Chris Zanobini, CA Grain and Feed, CA Seed Association, CA Warehouse Association, CA State Floral Association, CA Pear Growers Association, CA Bean Shippers Association; Debbie Murdock, Pacific Egg and poultry Written testimony: April 17, 2009
CACA2	Justin Oldfield, CA Cattlemen's Association Oral testimony: April 23, 2009
CALETC1	David Modisette, CA Electric Transportation Coalition; Will Barrett, American Lung Association in California; John Shears, Center for Energy Efficiency and Renewable Technologies; Tim Carmichael, Coalition for CleanAir; Daniel Emmett, Energy Independence Now; Danielle Fugere, Friends of the Earth; Roland Hwang, Natural Resources Defense Council; Saul Zambrano, Pacific Gas and Electric Company; Michael J. Gianunzio, Sacramento Municipal Utility District; William Zobel, San Diego Gas & Electric Company; Michael M. Hertel, Southern California Edison Company; Patricia Monahan, Union of Concerned Scientists Written testimony: April 14, 2009
CALETC2	David Modisette, CA Electric Transportation Coalition Oral testimony: April 23, 2009
CALSTART	Jamie Hall* and John Boesel, CALSTRAT Written testimony: April 15, 2009
CALUMET	Betsie Dent, Calumet Project Written testimony: April 6 2009
CAP1	Charlie Peters, Clean Air Performance Oral testimony: April 23, 2009
CAP2	Charlie Peters, Clean Air Performance

	Written testimony: April 23, 2009
CAPOZ	J. Capozzelli Written testimony: April 20, 2009
CAPP1	Rick Hyndman, CAPP Written testimony: April 22, 2009
CAPP2	Rick Hyndman, Canadian Assoc. of Petroleum Producers Oral testimony: April 23, 2009
CARLSON	Joyce Carlson, League of Women Voters Written testimony: April 3, 2009
CAUTHEN	Gerald Cauthen Written testimony: April 17, 2009
CAW	Nick Lapis, CA Against Waste Oral testimony: April 23, 2009
CBCOC1	Edwin Lombard, Sacramento Black Chamber of Commerce; Aubry Stone, California Black Chamber of Commerce; Pastor Robert Jones, The Amen Group; Carol Lee Tolbert, Civic Pride; Tara McClanahan; Darryl Jenkins, 100 Black Men; Julio Alvarado, Alvia Corporation Written testimony: April 23, 2009
CBCOC2	Edwin Lombard Management, CA Black Chamber Oral testimony: April 23, 2009
CBCOC3	Edwin Lombard, CA Black Chamber of Commerce Oral testimony: March 26, 2009
CBE1	Bill Gallegos and Greg Karras, Communities for a Better Environment Written testimony: April 20, 2009
CBE2	Greg Karras, Communities for a Better Environment Written testimony: April 20, 2009
CBE3	Greg Karras, Communities for a Better Environment Written testimony: December 8, 2009
CBE4	Greg Karras, Communities for a Better Environment Oral testimony: April 23, 2009
CBPA	Matthew Hargrove, CA Business Properties Association Oral testimony: April 23, 2009
CCA	Shankar Prasad, Coalition for Clean Air Oral testimony: April 23, 2009
CCCC	Jamie Knapp*, Vandana Bali, San Francisco Clean Cities Coalition; Margo Sidener, Silicon Valley Clean Cities Coalition; JoAnn Armenta, Southern California Association of Governments Clean Cities Coalition; Suzanne Seivright, Clean Cities Coachella Valley Region Written testimony: April 21, 2009
CCG	Marc LePage, Consul General, Canadian Consulate General Oral testimony: April 23, 2009
CCOC	Amisha Patel, California Chamber of Commerce Oral testimony: April 23, 2009

CCWI	Peter Anderson, Center for a Competitive Waste Industry Written testimony: April 22, 2009
CE1	Todd Campbell, Clean Energy Written testimony: April 17, 2009
CE2	Jonathan Burke, Clean Energy Written testimony: no date
CE3	Todd Campbell, Clean Energy Oral testimony: April 23, 2009
CE4	Todd Campbell, Clean Energy Oral testimony: March 26, 2009
CEERT1	John Shears, CEERT Oral testimony: April 23, 2009
CEERT2	John Shears, CEERT Written testimony: March 27, 2009
CERA1	Naomi Kim*, California Environmental Rights Alliance; Angela Johnson Meszaros and Jane Williams, AB32 Environmental Justice Advisory Committee Written testimony: April 21, 2009
CERA2	Naomi Kim, California Environmental Rights Alliance; Jane Williams, California Communities Against Toxics Written testimony: April 22, 2009
CERA3	Naomi Kim Oral testimony: April 23, 2009
CEVC	Joseph Irvin, CA Ethanol Vehicle Coalition Written testimony: April 13, 2009
CFC	Clayton McMartin II, Clean Fuels Clearinghouse Written testimony: April 17, 2009
CHCC1	Martin Fuentes, CHCC Oral testimony: April 23, 2009
CHCC2	Max Ordonez, CHCC Oral testimony: April 23, 2009
CHCOC1	Roy Perez, CA Hispanic Chamber of Commerce; Edwin Lombard California Black Chamber of Commerce; John Kabateck National Federation of Independent Business - California Written testimony: April 13, 2009
CHCOC2	Julian Canete, California Hispanic Chamber of Commerce Written testimony: April 23, 2009
CHCOC3	Julian Canete, CA Hispanic Chamber of Commerce Oral testimony: April 23, 2009
CHEVALIER	Marsha Chevalier Written testimony: April 5, 2009
CHEVRON1	Stephen D. Burns Written testimony: April 21, 2009
CHEVRON2	James Uihlein, Chevron Oral testimony: April 23, 2009

CHOREN	Alex Menotti*, William M. Guerry, Alexander D. Menotti on behalf of Choren USA Written testimony: April 15, 2009
CIOMA1	Jay McKeeman, CIOMA Written testimony: April 20, 2009
CIOMA2	Jay McKeeman, CIOMA Oral testimony: April 23, 2009
CLF1	Susan Reid*, Conservation Law Foundation; Arney Martella for Gina McCarthy, Connecticut Department of Environmental Protection; David Small, Delaware Department of Natural Resources & Environmental Control; David P. Littell, Maine Department of Environmental Protection; Shari T. Wilson, Maryland Department of the Environment; Laurie Burt, Massachusetts Department of Environmental Protection; Pete Grannis, New York Department of Environmental Conservation; Thomas S. Burack, New Hampshire Department of Environmental Services; Mark N. Mauriello, New Jersey Department of Environmental Protection; John Hanger, Pennsylvania Department of Environmental Protection; W. Michael Sullivan, Rhode Island Department of Environmental Management; Justin Johuson, Vermont Department of Environmental Conservation Written testimony: April 17, 2009
CLF2	Susan Reid, Conservation Law Foundation; Oral testimony: April 23, 2009
CMCC	James Duran, CMCC Oral testimony: April 23, 2009
CMTA	Dorothy Rothrock, CMTA Oral testimony: April 23, 2009
CNAES	Kurt Blase and Thomas J. Corcoran, Center for North American Energy Security Written testimony: April 22, 2009
CNGVC1	Pete Price, California Natural Gas Vehicle Coalition Written testimony: April 17, 2009
CNGVC2	Pete Price, California Natural Gas Vehicle Coalition Oral testimony: April 23, 2009
CO2STR	William Wason, CO2 Star Written testimony: April 22, 2009
COF	Bob Wasserman, City of Fremont Written testimony: April 15, 2009
COI	Rick Longobart, City of Inglewood Written testimony: April 22, 2009
COLTON	Steve Colton Written testimony: April 2, 2009
COLUMBIA	Nickolas Themelis, Columbia University

	Written testimony: April 6, 2009
COMF1	Michael Redemer, Community Fuels Written testimony: April 20, 2009
COMF2	Michael Redemer, Community Fuels Written testimony: April 23, 2009
COMF3	Michael Redemer, American Biodiesel Oral testimony: April 23, 2009
CON10U	James Brady, Con10u Inc. Written testimony: non-dated
CONOCO	H. Daniel Sinks, ConocoPhillips Written testimony: April 21, 2009
CPB	V. John White, Clean Power Campaign Written testimony: April 21, 2009
CPE	David Bruderly, Clean Power Engineering Written testimony: April 14, 2009
CRPE1	Sofia Sarabia, The Center on Race, Poverty, & the Environment; Bill Gallegos, Communities for a Better Environment; Tom Frantz, Association of Irrigated Residents; Juliette Anthony; Raquel Ortega Written testimony: April 22, 2009
CRPE2	Sofia Sarabia, The Center on Race, Poverty, & the Environment Oral testimony: April 23, 2009
CSBR1	Betty Jo Toccoli, CA Small Business Roundtable; California Small Business Association, California Small Business Roundtable; John Kabateck, National Federation of Independent Business - California; Aubry Stone, California Black Chamber of Commerce; Joel Ayala, California Hispanic Chamber of Commerce; Willie Galvan, American or Forum of California Matt Sutton, California Restaurant Association; John Handley, California Independent Grocers Association, Joel Fox, Small Business Action Committee Written testimony: April 10, 2009
CSBR2	Betty Jo Toccoli, CA Small Business Roundtable Written testimony: April 20, 2009
CSBR3	Sanjay Varshney and Dennis J. Tootelian, CA State University, Sacramento Written testimony: April, 2009
CSBR4	Sanjay Varshney, on behalf of CA Small Business Roundtable Oral testimony: April 23, 2009
CSC	Senator Mimi Walters, California State Senate Written testimony: April 21, 2009
CSD	Thomas Alspaugh, City of San Diego

	Written testimony: April 13, 2009
CVAQ	Tom Frantz and John Shears, CVAQ Energy Committee Written testimony: April 21, 2009
CWP	Pete Montgomery*, Greg Hayes and Warren Smith, Clean World Partners Written testimony: April 7, 2009
DABBR	Anthony Dabbracci Written testimony: April 2, 2009
DALE	Virginia H. Dale Written testimony: April 22, 2009
DANDREA	Daria D'Andrea Written testimony: April 3, 2009
DSOUZA	Gladwyn d'Souza Written testimony: April 10, 2009
DUPONT1	Thomas Jacob, Dupont Company Written testimony: April 21, 2009
DUPONT2	Tom Jacob, Dupont Co. Oral testimony: April 23, 2009
EC	Caitlyn Toombs, Environment California Written testimony: April 13, 2009
ECOMETRICA	Richard Tippet, Ecometrica Ltd Written testimony: April 22, 2009
EDENIQ	Will Gardenswartz, Edeniq Oral testimony: April 23, 2009
EDF1	Tim O'Connor, Environmental Defense Fund Written testimony: March 26, 2009
EDF2	Tim O'Connor, Environmental Defense Fund Written testimony: April 17, 2009
EDF3	Tim O'Connor, Environmental Defense Fund Oral testimony: April 23, 2009
EDF4	Derek Walker, Environmental Defense Fund Oral Testimony: March 26, 2009
EE1	Bob Epstein and Meera Balakumar, Environmental Entrepreneurs (E2); Dan Adler, California Clean Energy Fund; Lee Bailey and Jim McDermott, US Renewables Group, LLC; Josh Becker, New Cycle Capital, LLC; Eric M. Bowen, Tellurian Biodiesel, Inc.; Jerry Caulder and Arama Kukutai, Finistere Ventures, LLC; Lawrence S. Gross, Edeniq, Inc.; J. William Haywood, LS9, Inc.; Kinkead Reiling, Amyris Biotechnologies, Inc.; Jim Macias, Ted Kniesche, Fulcrum BioEnergy, Inc.; Jeffrey A. Martin, Yulex Corporation; Jack Oswald, SynGest, Inc.; Tom Soto, Craton Equity Partners; Sanjay Wagle VantagePoint Venture Partners, Inc.; Steve Westly, The Westly Group; Paul Zorner, Hawaii BioEnergy, LLC Written testimony: April 15, 2009

EE2	Bob Epstein, Environmental Enterprises Oral Testimony: April 23, 2009
EESI1	Carol Werner, Environmental and Energy Study Institute Written testimony: March 16, 2009
EESI2	Carol Werner, Environmental and Energy Study Institute Written testimony: April 10, 2009 ** Duplicate submission of March 16, 2009 letter**
EIN1	Remy Garderet and Daniel Emmett, Energy Independence Now Written testimony: March 26, 2009
EIN2	Remy Garderet and Daniel Emmett, Energy Independence Now Written testimony: April 22, 2009
EIN3	Remy Garderet, Energy Independence Now Oral Testimony: April 23, 2009
EMA	Joseph Suchecki, Engine Manufacturers Association Written testimony: April 22, 2009
ENE	Emily Bateson, Environment Northeast Written testimony: April 22, 2009
ENVCLN1	Jamie Knapp, Environmental Coalition Oral Testimony: April 23, 2009
ENVCLN2	LCFS supporters list submitted by Jamie Knapp Written testimony: April 22, 2009
ERG1	Philip Treanor, Energy Recovery Group Written testimony: March 25, 2009
ERG2	Philip Treanor, Energy Recovery Group Written testimony: March 25, 2009
EUCA	Tara McGovern, EUCA Written testimony: March 10, 2009
FORMLETTER1	Malcolm Gaffney **5 additional commenters submitted similar comments** Written testimony: April 3, 2009
FORMLETTER2	Jennifer Canvasser **72 additional commenters submitted similar comments** Written testimony: April 6, 2009
FORMLETTER3	Maira Rodriguez et al. **501 additional signatories to this form letter** Written testimony: April 9, 2009
FORMLETTER4	Ofelia Alvarado **32 additional commenters submitted similar comments** Written testimony: April 17, 2009
FORMLETTER5	Thomas Blaney **1500 additional commenters submitted same comments** Written testimony: April 17, 2009
FORMLETTER6	Maya Puerta **30 additional commenters submitted similar comments**

	Written testimony: April 22, 2009
FOTE1	Kate McMohan*, Friends of the Earth; Daniel Magraw, Center for International Environmental Law; John DeCock, Clean Water Action; Rodger Schlickeisen, Defenders of Wildlife; Margie Alt, Environment America; Fred Krupp, Environmental Defense Fund; Brent Blackwelder, Friends of the Earth; Frances Beinecke, Natural Resources Defense Council; Tom Kiernan, National Parks Conservation Association; Larry Schweiger, National Wildlife Federation; Kevin Knobloch, Union of Concerned Scientists Written testimony: April 14, 2009
FOTE2	Danielle R. Fugere Written testimony: April 22, 2009
FOTE3	Danielle Fugere, Friends of the Earth Oral testimony: April 23, 2009
FULCRUM	Ted Kniesche, Fulcrum Oral testimony: April 23, 2009
GDSF	Eric Smith, Green Depot San Francisco Written Testimony: April 22, 2009
GE1	Gen. Wesley Clark, Growth Energy Oral Testimony: April 23, 2009
GE2	Dr. Mark Stowers Written Testimony: April 23, 2009
GE3	Tom Buis, Growth Energy Written Testimony: April 23, 2009
GMAGRP	Geoff Moody, Grocery Manufacturers Association Written Testimony: April 17, 2009
GOVTCANADA1	Nadia Scipio Del Campo*, Government of Canada Lisa Raitt, Government of Canada- Written Testimony: April 21, 2009 Michael Wilson, Government of Canada- Written Testimony: April 22, 2009
GOVTCANADA2	Mark LePage, Government of Canada Written Testimony: April 23, 2009
GTCLLC	Joel Balbien, Green Tech Consulting, LLC Written Testimony: April 2, 2009
HALL	Robert Hall (No Affiliation Given) Written Testimony: April 2, 2009
HAMILTON	Dr. Barbara & Mr. To Hamilton (No Affiliation Given) Written Testimony: April 17, 2009
HARRIS	Kevin Harris (No Affiliation Given) Written Testimony: March 21, 2009
HCCCCC	Eric Maldonado, Hispanic Chamber of Commerce of Contra Costa County Written Testimony: April 23, 2009

HNCA1	Robert Meagher, MD Oral Testimony: April 23, 2009
HNCA2	William Barrett*, American Lung Association- Health Network for Clean Air Jonathan Alexander, MD; Laura Applebaum, MD; Samuel Applebaum, MD; Kamran Azmoudeh, DDS; Zindy Baltazar, RN; Laura Barrett, RN; Malik Baz, MD; Laura Berke, RN; Victoria Bermudez, RN; Wendy Bernstein, MD; Gloria Bertucci, MD; Cheryl Bezucha, RCP; Marcia B Marthaler, RN; Kelly Burke, DO; Ken Burke, PhD; Thomas Bush, MD; Lisa Caine, RCP; Carolyn Calfee, MD; Nicole Calvillo, MD; Jim Carpenter, MD; Gaile Carr, RN; Jodi Casperite, RN; Alia Chiappella, RN; Valerie Clark, RN; Somjai Cochran, RN; Richard Cooper, PhD; Allen Cortez, MD; Adam Davis, MA, MPH; Anthony DeRiggi, MD; Marc Diamond, MD; Michael Dietrick, MD; Diane Dooley, MD; Sara Dore, RN; Teri Duarte, MPH, RD; Joan Edelstein, RN; Laraine Feruson, RN; Merhita Ferrer, RN; William Flinn, RN; Rene Fong, RCP; Jan Gameroz, RN; Christine Garvey, FNP, MSN, FAACVPR; Anthony Gerber, MD; Linda Gibson, RN; Robert Gould, MD; Andrea Graboff, RPT; Victoria Hall, RN; Kevin Hamilton, RRT, RCP; Jeff Haney, MD; Susan Harris, RN; Leslie Hata, DDS; Lana Hilling, RCP, FAACVPR; Nathan Hitzeman, MD; Guenter Hofstadler, MD; Peter Joseph, MD MD; J. Michael Kelly, MD; Anne Kennedy, RCP; Janice Kim, MD; Susan King, RN; Dian Kiser, PhD; Jon Koff, MD; Jane Lash-Santana, RN; Lorianne Leard, MD; Darlene Lee Young, NP; Bill Legere, RCP; Julie Lester, RN; Jonathan Lukoff, MD; Carol Maehr, RN; Jane Martin, DrPH; Michael Martin, MD; Amanda Martinez, RN; Robert Martinez, MD; Julie McKown, RCP; Kelley Meade, MD; Olga Mercado, PA-C; Christine Millhollin, RN; Helen Cherie Mitchell, RN; Debra Nau, RN; Amy O'Neil, RN; Sonal Patel, MD; Judith Pekala, RN; Teri Pena, RRT, CRTT; Stephen Perlman, MD; Nancy Perrin, RCP; Meda Rebecca, PhD; Gregory Redmond, MD; Gulrukh Rizvi, MD; Kenneth Saffier, MD; Mark Schenker, MD; Tara Scott, MD; Eva Severaid, RN; Sherwin Tongson, RN; Brigitte VanderWalt, RN; Priscilla Vassallo, RN; Valerie Vogel, RRT, RCP; Marianne Walker, RN; Harry Wang, MD; Lisa Ward, MD; Madelyn Weiss, MD; Amy Whittle, MD; Melinda Wilson, RN Written Testimony: April 22, 2009
HNCA3	Robert Meagher*, American Lung Association- Health Network for Clean Air; Jonathan Alexander, MD; Laura Applebaum, MD; Samuel Applebaum, MD; Kamran Azmoudeh, DDS; Zindy Baltazar, RN; Laura Barrett, RN;

	<p>Malik Baz, MD; Laura Berke, RN; Victoria Bermudez, RN; Wendy Bernstein, MD; Gloria Bertucci, MD; Cheryl Bezucha, RCP; Marcia B Marthaler, RN; Kelly Burke, DO; Ken Burke, PhD; Thomas Bush, MD; Lisa Caine, RCP; Carolyn Calfee, MD; Nicole Calvillo, MD; Jim Carpenter, MD; Gaile Carr, RN; Jodi Casperite, RN; Alia Chiappella, RN; Valerie Clark, RN; Somjai Cochran, RN; Richard Cooper, PhD; Allen Cortez, MD; Adam Davis, MA, MPH; Anthony DeRiggi, MD; Marc Diamond, MD; Michael Dietrick, MD; Diane Dooley, MD; Sara Dore, RN; Teri Duarte, MPH, RD; Joan Edelstein, RN; Laraine Feruson, RN; Merhita Ferrer, RN; William Flinn, RN; Rene Fong, RCP; Jan Gameroz, RN; Christine Garvey, FNP, MSN, FAACVPR; Anthony Gerber, MD; Linda Gibson, RN; Robert Gould, MD; Andrea Graboff, RPT; Victoria Hall, RN; Kevin Hamilton, RRT, RCP; Jeff Haney, MD; Susan Harris, RN; Leslie Hata, DDS; Lana Hilling, RCP, FAACVPR; Nathan Hitzeman, MD; Guenter Hofstadler, MD; Peter Joseph, MD MD; J. Michael Kelly, MD; Anne Kennedy, RCP; Janice Kim, MD; Susan King, RN; Dian Kiser, PhD; Jon Koff, MD; Jane Lash-Santana, RN; Lorianne Leard, MD; Darlene Lee Young, NP; Bill Legere, RCP; Julie Lester, RN; Jonathan Lukoff, MD; Carol Maehr, RN; Jane Martin, DrPH; Michael Martin, MD; Amanda Martinez, RN; Robert Martinez, MD; Julie McKown, RCP; Kelley Meade, MD; Olga Mercado, PA-C; Christine Millhollin, RN; Helen Cherie Mitchell, RN; Debra Nau, RN; Amy O'Neil, RN; Sonal Patel, MD; Judith Pekala, RN; Teri Pena, RRT, CRTT; Stephen Perlman, MD; Nancy Perrin, RCP; Meda Rebecca, PhD; Gregory Redmond, MD; Gulrukh Rizvi, MD; Kenneth Saffier, MD; Mark Schenker, MD; Tara Scott, MD; Eva Severaid, RN; Sherwin Tongson, RN; Brigitte VanderWalt, RN; Priscilla Vassallo, RN; Valerie Vogel, RRT, RCP; Marianne Walker, RN; Harry Wang, MD; Lisa Ward, MD; Madelyn Weiss, MD; Amy Whittle, MD; Melinda Wilson, RN</p> <p>Written Testimony: April 22, 2009</p>
HNCA4	<p>Will Barrett, American Lung Association</p> <p>Oral Testimony: April 23, 2009</p>
HOFF	<p>Forest Stephen Hoff (No Affiliation Given)</p> <p>Written Testimony: April 23, 2009</p>
HONDA	<p>Ryan Harty, Honda R&D Americas</p> <p>Written Testimony: April 23, 2009</p>
HTC	<p>Lee Hobbs, Hobbs Trucking Co.</p> <p>Written Testimony: April 17, 2009</p>
ICM1	<p>David Vander Griend, William J. Roddy*, ICM</p> <p>Written Testimony: April 15, 2009</p>
ICM2	<p>David Vander Griend, William J. Roddy*, ICM</p>

	Written Testimony: April 15, 2009
ICM3	David Vander Griend, William J. Roddy*, ICM Written Testimony: April 15, 2009
ILCORN	Rob Elliot, Illinois Corn Growers Association Written Testimony: April 16, 2009
IOWACORN	Gary Edwards, Iowa Corn Growers Association Written Testimony: April 17, 2009
IRELLC	Richard Ruebe, Illinois River Energy, LLC Written Testimony: April 14, 2009
ISU1	Robert Brown, Bioeconomy Institute, Iowa State University; Hans van Leeuwen, Deng, BCEE, PE, Iowa State University; Richard M. Cruse, Iowa Water Center, Iowa State University; John F. McClelland, IPRT/Ames Laboratory-USDOE; Theodore J. Heindel, Iowa State University; Glenn Norton, Iowa State University; Carl J. Bern PhD, PE, Iowa State University; Alicia Carriquiry, Iowa State University; Robert J. Angelici, Iowa State University; Mark A. Edelman, Iowa State University; Stephen H. Howell, Agricultural Marketing Resource Center, Iowa State University; Don Hofstrand, Iowa State University; Stuart Birrell, Iowa State University; John G. Verkade, Iowa State University; Kenneth J. Moore, Iowa State University; David Gerwell, PhD, Iowa State University; Jill Euken, Bioeconomy Institute, Iowa State University; John A. Miranowski, Institute of Science and Society, Iowa State University Written Testimony: April 6, 2009
ISU2	D. Raj Raman PhD PE, Iowa State University Written Testimony: April 3, 2009
IWLA	Patty Senecal*; Joel D. Anderson, International Warehouse Logistics Association Written Testimony: April 22, 2009
IWLAGRP	Joel D. Anderson*, International Warehouse Logistics Association; Lucy Dunn, Orange County Business Council; Stephanie Williams, Western States Goods Movement Alliance; B.J. Patterson, Distribution Management Association; Miguel Silva, West State Alliance; William Hudson, International Assn. of Refrigerated Warehouses; Rex S. Hime, California Business Properties Assn.; Chuck Shaw, Int'l Council of Shopping Centers; Jim Camp, National Assn of Industrial and Office Properties; Michael Lightman, Harbor Truckers for Sustainable Future; Daniel Meylor, LA Customs Brokers & Freight Forwarders Assn.; Jack Hubbard, Pacific Coast Council of Customs Brokers & Freight Forwarders Assn. Written Testimony: April 20, 2009
JBI	Blake A. Simmons* Joint BioEnergy Institute, Sandia

	National Laboratories; Harvey W. Blanch PhD UC Berkeley; Bruce E. Dale PhD, Michigan State University Written Testimony: April 20, 2009
JMBM	Peter Mieras, JMBM LLC Oral Testimony: April 23, 2009
KELLER	Nathan Keller (No Affiliation Given) Written Testimony: April 2, 2009
KEMPF	James Kempf (No Affiliation Given) Written Testimony: March 7, 2009
KLINE	Keith Kline*, (No Affiliation Given); Gbadebo Oladosu (No Affiliation Given) Written Testimony: April 22, 2009
KORC1	Robert H. Richards, Kern Oil & Refining Co. Written Testimony: April 22, 2009
KORC2	Robert H. Richards, Kern Oil & Refining Co. Oral Testimony: April 23, 2009
KORC3	Jerry Frost, Kern Oil & Refining Co. Oral Testimony: April 23, 2009
KORC4	Jerry Frost, Kern Oil & Refining Co. Written Testimony: April 23, 2009
KVOLS	Jason Kvols (No Affiliation Given) Written Testimony: April 22, 2009
LBA1	Ruben Juaregui, Latino Business Assn. Oral Testimony: April 23, 2009
LBA2	Ruben Juaregui, Latino Business Assn. Written Testimony: April 23, 2009
LEE	Joe Lee (No Affiliation Given) Written testimony: April 20, 2009
LEEUK	Nicholas Lee (No Affiliation Given) Written testimony: April 23, 2009
LEONARD	Kirk Leonard (No Affiliation Given) Written testimony: April 16, 2009
LUFT	Gal Luft (No Affiliation Given) Written testimony: April 19, 2009
LUITJENS	Mark Luitjens (No Affiliation Given) Written testimony: April 22, 2009
MADEP	William Space*, MA Dept. of Environmental Protection; Amey Marella for Gina McCarthy, Connecticut Department of Environmental Protection; David Small, Delaware Department of Natural Resources & Environmental Control; David P. Littell, Maine Department of Environmental Protection; Shari T. Wilson, Maryland Department of the Environment; Laurie Burt, Massachusetts Department of Environmental Protection; Pete Grannis, New York Department of Environmental Conservation; Thomas S. Burack, New Hampshire Department of Environmental

	Services; Mark N. Mauriello, New Jersey Department of Environmental Protection; John Hanger, Pennsylvania Department of Environmental Protection; W. Michael Sullivan, Rhode Island Department of Environmental Management; Justin Johnson, Vermont Department of Environmental Conservation Written testimony: April 17, 2009
MALECHIKOS	Nikolas Malechikos (No Affiliation Given) Written testimony: March 22, 2009
MARZ	Carl Marz (No Affiliation Given) Written testimony: April 20, 2009
MASCHHOFFS	Aaron Gaines PhD, The Maschhoffs LLC Written testimony: April 22, 2009
MATTSSON	William and Hiroko Mattsson (No Affiliation Given) Written testimony: April 3, 2009
MAURIELLO	Glenn Mauriello (No Affiliation Given) Written testimony: April 20, 2009
MCGA	Jody E. Pollok-Newsom*, Michigan Corn Growers Assn.; Written testimony: April 20, 2009
MDSA	Thomas MacDonald, MacDonald Schwieger Associates Written testimony: April 20, 2009
MDV1	Will Coleman, Mohr Davidow Ventures; Andrew Friendly, Advanced Technology Ventures; Erik Straser, Mohr Davidow Ventures; Jason Matlof, Battery Ventures; Josh Green, Mohr Davidow Ventures; Kelsey B. Lynn, Firelake Capital Management, LLC; Martin L. Lagod, Firelake Capital Management, LLC; Maurice Gunderson, CMEA Capital; Paul Holland, Foundation Capital; Steve Golby, Venrock Written testimony: April 21, 2009
MDV2	Will Coleman, Mohr Davidow Ventures Oral testimony: April 23, 2009
MONSANTO	Mike Edgerton, Monsanto Written testimony: April 14, 2009
NBB	Shelby Neal, National Biodiesel Board Written testimony: April 21, 2009
NCB	F. Jon Holzfaster, National Corn Board Written testimony: April 13, 2009
NCERC1	John Caupert MS, National Corn to Ethanol Research Center (NCERC) Written testimony: April 5, 2009
NCERC2	John Caupert MS*, Brian Wren PhD, National Corn to Ethanol Research Center (NCERC) Written testimony: April 14, 2009
NCERC3	John Caupert MS*, Dr. Yan Zhang, National Corn to Ethanol Research Center (NCERC) Written testimony: April 5, 2009

NCGA	Bob Dickey, National Corn Growers Assn. (NCGA) Written testimony: April 17, 2009
NCSU	Michelle C. Marra, Barry K. Goodwin, Nicholas E. Piggott, North Carolina State University (NCSU) Written testimony: April 13, 2009
NDSU	William Wilson, North Dakota State University (NDSU) Written testimony: April 20, 2009
NEB	Todd Sneller (No Affiliation Given); Kenneth G. Cassman, Adam J. Liska, University of Nebraska-Lincoln; Bill Northey, Iowa Secretary of Agriculture; Mark Stowers PhD, Poet LLC; Mark E. Calmes, Archer Daniels Midland; Gerson Santos- Leon, Abengoa Bioenergy; Karen Margrethe Oxenboll, Novozymes; Bob Dinneen, Renewable Fuels Association; Kelly Brunkhorst, Nebraska Corn Board Written testimony: February 27, 2009
NESCAUM	Matt Solomon, The Clean Air Association of the Northeast States (NESCAUM) Written testimony: April 23, 2009
NESCAUM2	Matt Solomon, NESCAUM Oral testimony: April 23, 2009
NESTE1	Tom Fulks, Neste Oil Oral testimony: March 26, 2009
NESTE2	Tom Fulks, Neste Oil Oral testimony: April 23, 2009
NFA1	Brooke Coleman, New Fuels Alliance; Vinod Khosla, Khosla Ventures; Carlos Riva, Verenium Corporation; Neil Koehler, Pacific Ethanol; Colin South, Mascoma Corporation; Neco Sumait, BlueFire Ethanol; Mitch Mandich, Range Fuels, Inc.; Mark Noetzel, Cilion, Inc.; Bill Honnef, VeraSun Energy; Jef Sharp, SunEthanol; Patrick R. Gruber, Gevo Incorporated; Dr. Frances H. Arnold, California Institute of Technology; Ken DeCubellis, Altra Biofuels; Randy Kramer, KL Energy; Jeff Passmore, Iogen Corporation; Steve Gatto, BioEnergy International, LLC; John Cruikshank, New Planet Energy, LLC; Michael Raab, Agrivida, Inc.; David R. Rubenstein, California Ethanol+Power LLC; Connie Lausten, New Generation Biofuels; James P. Imbler, ZeaChem, Inc.; Larry Lenhart, Catilin Inc.; Nathalie Hoffman, California Renewable Energies, LLC; Jeff Stroburg, Renewable Energy Group; David Morris, Institute for Local Self Reliance (ILSR); Dr. Bruce Dale, Michigan State University; Jeff Plowman, Sustainable Biodiesel Alliance; Rahul Iyer, Primafuel, Inc.; Richard W. Hamilton, Ceres, Inc.; Richard Gillis, Energy Alternative Solutions, Inc. Written testimony: October 23, 2008
NFA2	R. Brooke Coleman, Andrew Schuyler, New Fuels Alliance

	Written testimony: April 22, 2009
NFA3	Brooke Coleman, New Fuels Alliance Oral testimony: April 23, 2009
NFIB	John Kabatack, NFIB Oral testimony: April 23, 2009
NOVOZYM1	Mark L. Perlis, Dickstein Shapiro LLC; Lars Hansen, Novozymes North America, Inc. Written testimony: April 22, 2009
NOVOZYM2	Claus Fuglsang, Novozymes Oral testimony: April 23, 2009
NRDC1	Roland Hwang*, Natural Resources Defense Council (NRDC); Rebecca R. Wodder, American Rivers; John Flicker, Audubon Society; Armond Cohen, Clean Air Task Force; John De Cock, Clean Water Action; Rodger Schlickeisen, Defenders of Wildlife; Trip Van Noppen, Earthjustice; Margie Alt, Environment America; Richard Wiles, Environmental Working Group; Brent Blackwelder, Friends of the Earth; Gene Karpinski, League of Conservative Voters; Larry Schweiger, National Wildlife Federation; Frances Beinecke, Natural Resources Defense Council; Rob Sisson, Republicans for Environmental Protection; Carl Pope, Sierra Club; Alden Meyer, Union of Concerned Scientists; William H. Meadows, The Wilderness Society Written testimony: March 19, 2009
NRDC2	Simon Mui*, NRDC; Kathy Andria, American Bottom Conservancy; Bonnie Holmes-Gen, American Lung Association of California; Steve Kozel, Calumet Project; John Shears, Center for Energy Efficiency and Renewable Technologies; Peter Taglia, Clean Wisconsin; Lynn Thorp, Clean Water Action; Will Horter, Dogwood Initiative; Shankar Prasad, Coalition for Clean Air; Charles Griffith, Ecology Center; Michael Marx, Corporate Ethics International; Michael Noble, Fresh Energy; Bruce Baizel, Earthworks; Timothy Telleen-Lawton, Environment America; Matt Price, Environmental Defence Canada; Daniel Fugere, Friends of the Earth; Caitlyn Toombs, Environment California; Ed Cable, Save Union County; Aaron Sanger, ForestEthics; Denny Larson, Global Community Monitor; Tom Goldtooth, Indigenous Environmental Network; Andrea Carmen, International Indian Treaty Council; Liz Barratt-Brown, Natural Resources Defense Council; Steve Kretzmann, Oil Change International; Dan Woynillowicz, Pembina Institute; Michael Brune, Rainforest Action Network; Patricia Monahan, Union of Concerned Scientists Written testimony: April 13, 2009

NRDC3	Simon Mui, Roland Hwang, NRDC Written testimony: April 23, 2008 (errata in testimony, actually April 23, 2009)
NRDC4	Roland Hwang, NRDC Oral testimony: April 23, 2009
NRDC5	Simon Mui, NRDC Oral testimony: April 23, 2009
NRDC6	Roland Hwang, NRDC Oral testimony: March 26, 2009
OCGA	John Davis, Dwayne Siekman, Ohio Corn Growers Assn. (OCGA) Written testimony: April 15, 2009
OCTA	Jim Kenan, Orange County Transportation Authority (OCTA) Written testimony: April 22, 2009
OEC	Chris Hagerbaumer, Oregon Environmental Council Written testimony: April 8, 2009
OLSEN	Mariette Olsen (No Affiliation Given) Written testimony: April 5, 2009
ORTEGA	Michelle Ortega (No Affiliation Given) Written testimony: April 17, 2009
PE1	Tom Koehler, Pacific Ethanol Inc. Oral testimony: March 26, 2009
PE2	Tom Koehler, Pacific Ethanol Inc. Oral testimony: April 23, 2009
PEERREVIEW1	Linsey C. Marr, Virginia Tech Written testimony: March 31, 2009
PEERREVIEW2	John Reilly, Massachusetts Institute of Technology Written testimony: April 6, 2009
PEERREVIEW3	Valerie Thomas, Georgia Institute of Technology Written testimony: April 14, 2009
PEERREVIEW4	Denise L. Mauzerall, Princeton University Written testimony: April 10, 2009
PFT	Laurie A. Wayburn, The Pacific Forest Trust Written testimony: April 15, 2009
PG&E	James Larsen, Pacific Gas & Electric Co. (PG&E) Oral testimony: April 23, 2009
PIA	Jay Friedland, Plug In America Written testimony: April 21, 2009
PLS	Richard Ottinger, Pace Law School Written testimony: March 19, 2009
PMPBRAZIL	Altacir Bunde, Popular Movement of Peasants, Brazil Oral testimony: April 23, 2009
POET1	Jeff Broin, Poet Written testimony: April 22, 2009
POET2	Mark Stowers, Poet Oral testimony: April 23, 2009

POUSMAN	Robert Pousman (No Affiliation Given) Written testimony: April 2, 2009
PP1	Gary Grimes, Paramount Petroleum Written testimony: April 23, 2009
PP2	Gary Grimes, Paramount Petroleum Oral testimony: April 23, 2009
PRIMAFUEL	Rahul Iyer, Primafuel Inc. Written testimony: April 10, 2009
PRINCETON	Timothy D. Searchinger, Princeton University; Daniel Kammen, UC Berkeley Written testimony: April 23, 2009
PRX	William J. Hudson, ProExporter Network Written testimony: April 15, 2009
PWSP	Kenneth Manaster, Pillsbury Winthrop Shaw Pittman Oral testimony: April 23, 2009
RAN1	Andrea Samulon, Rainforest Action Network Written testimony: April 20, 2009
RAN2	Brant Olson, Rainforest Action Network Oral testimony: April 23, 2009
RAN3	Andrea Samulon, Rainforest Action Network Oral testimony: April 23, 2009
REPLLC	Matt Gregori, Renewable Energy Products, LLC Written testimony: April 21, 2009
RFA1	Geoff Cooper, Renewable Fuels Association Written testimony: April 17, 2009
RFA2	Geoff Cooper, Renewable Fuels Assoc. Oral testimony: April 23, 2009
RUBIN	David Rubin Written testimony: April 13, 2009
SALAZAR	Joe Salazar Written testimony: April 10, 2009
SALVARYN	Jeff Salvaryn Written testimony: April 2, 2009
SBCTC	Robert Balgenorth, State Building and Construction Trade Council of California Written testimony: April 20, 2009
SBLLC	Mark Roberts Written testimony: April 22, 2009
SCAQMD1	Barry Wallerstein, SCAQMD Written testimony: April 17, 2009
SCAQMD2	Paul Wuebben, SCAQMD Oral testimony: April 23, 2009
SCAQMD3	Paul Wuebben, SCAQMD Written testimony: April 23, 2009
SCE	Gary Schoonyan, Southern CA Edison Oral testimony: April 23, 2009

SCOTT	Mike Scott Written testimony: April 2, 2009
SCPPA	Norman Pedersen; Southern California Public Power Author Written testimony: April 22, 2009
SDCHCC	Marco Polo Cortes; San Diego Hispanic Chamber Written testimony: April 23, 2009
SDCUC	David Fremark, South Dakota Corn Utilization Council Written testimony: April 15, 2009
SDLAC	Frank Caponi, Sanitation Districts of Los Angeles County Oral testimony: April 23, 2009
SEMPRA1	Taylor Miller, Sempra Energy Written testimony: April 15, 2009
SEMPRA2	Taylor Miller, Sempra Energy Oral testimony: April 23, 2009
SFB1	James Lutch, Simple Fuels Bio-diesel Oral testimony: April 23, 2009
SFB2	James Lutch, Simple Fuels Biodiesel Written testimony: April 23, 2009
SFVMAPA1	Anibal Guerrero, San Fernando Valley Chapter of the Mexican American Political Association Oral testimony: March 26, 2009
SFVMAPA2	Anibal Guerrero, San Fernando Valley Oral testimony: April 23, 2009
SHAFFER1	Steve Shaffer, Environmental Consulting for Agriculture Written testimony: April 22, 2009
SHAFFER2	Steve Shaffer, Environmental Consulting for Agriculture Oral testimony: April 23, 2009
SHAW	Gabrielle Shaw Written testimony: April 22, 2009
SHCC1	Steve Gondola, Sacramento Chamber of Commerce Written testimony: April 23, 2009
SHCC2	Steve Gondola, Sacramento Hispanic Chamber of Commerce Oral testimony: April 23, 2009
SHELL	James Armstrong, Shell Oil Company; Randy Armstrong, Shell Oil Company; Clay Calkin, Shell Oil Company Written testimony: April 13, 2009
SIERRACLB1	John Cordes, Sierra Club Written testimony: April 4, 2009
SIERRACLB2	Bill Magavern, Sierra Club California Written testimony: April 17, 2009
SIERRACLB3	Bill Magavern, Sierra Club California Written testimony: April 17, 2009
SIERRARES	James Lyons, Sierra Research Written testimony: April 22, 2009
SJCHCC1	Mark Martinez, San Joaquin Co Hispanic Chamber of

	Commerce Oral testimony: April 23, 2009
SJCHCC2	Mark Martinez, SJC Hispanic Chamber Written testimony: April 23, 2009
SJCHCC3	Jesus Vargas, San Joaquin County Hispanic Chamber of Commerce Written testimony: April 23, 2009
SOI	Chester Culver, State of Iowa; Brian Jennings, Office of the Governor and Lt. Governor Written testimony: April 22, 2009
SOLOMON	Chiho and Richard Solomon Written testimony: April 5, 2009
STANFORD	Ware Kuschner, Stanford University Written testimony: April 17, 2009
STAUB	Patricia Staub, Not a lobbyist = just a farmer Written testimony: April 22, 2009
STEILZ	Jim Steitz Written testimony: April 21, 2009
SUDERMAN	Arlan Suderman, Farm Futures Written testimony: April 21, 2009
SUSCON	Ashley Boren, Sustainable Conservation Written testimony: March 18, 2009
SVHCC	James Duran, Silicon Valley Hispanic Chamber Written testimony: April 23, 2009
TELLURIAN	Eric Bowen, Tellurian Oral testimony: April 23, 2009
TESORO1	Lynn D. Westfall, Tesoro Written testimony: April 20, 2009
TESORO2	Dwight Stevenson, Tesoro Oral testimony: April 23, 2009
TNSP	Frankie Sturm, Truman National Project*; Robert "Bud" McFarlane, U.S. Marine Corps; William C. Holmberg, U.S. Marine Corps (retired); David R. Adams, U.S. Marine Corps and ARNG; William Banta, U.S. Marine Corps, Merton J. Batchelder, Jr., U.S. Marine Corps; Rye Barcott, U.S. Marine Corps; John L. Berman, U.S. Air Force; Joseph E. Bles, U.S. Marine Corps & USAR (retired); Herbert W. Bruch, U.S. Navy (retired); Edward A. Burkhalter, Jr., U.S. Navy (retired); Vivian T. Chen, U.S. Public Health Service (retired); Robert C. Cherry, U.S. Marine Corps; Robert L. Church, U.S. Navy; Paul Clarke, U.S. Air Force; Charles G. Cooper, U.S. Navy; William S. Daniel, U.S. Marine Corps (retired); Robert Diamond, U.S. Navy; Russell Dramstad, U.S. Army (retired) & South Dakota National Guard (retired); Robert F. Dunn, U.S. Navy (retired); Michael T. Eckhart, U.S. Navy; Michael Edwards, U.S. Marine Corps; Christopher Finan, U.S. Air

	<p>Force; Joel N. Gordus, U.S Air Force; William P. Gorski, U.S. Marine Corps (retired); John J. Grace, U.S. Marine Corps; Peter L. Hilgartner, U.S. Marine Corps (retired); William P.T. Hill, U.S. Marine Corps; Scott Holcomb, U.S. Army; William E. Hutchison, U.S. Marine Corps (retired); Erica Jeffries, U.S. Army; Ted Kaehker, U.S Navy (retired); Leland S. Kollmorgen, U.S. Navy (retired); Gerald E. Kuecker, U.S. Navy; Peter Lohman, U.S. Army; William R. Maloney, U.S. Marine Corps (retired); William T. Marin, U.S. Navy (retired); Deny V. McGinn, U.S. Navy (retired); Michael W. McGowan, U.S. Air Force; Jason Mills, U.S. Marine Corps; Melissa Epstein-Mills, U.S. Marine Corps; James Morin, U.S. Army; Donald H. Morton, U.S. Navy (retired); Philip Miller Pahl, U.S. Air Force (retired); Charles E. Parker, U.S. Army Reserve; Jonathan Powers, U.S. Army; Douglas Raymond, U.S. Army; Brooke F. Read, Jr., U.S. Marine Corps; Alex Rossmiller, Defense Intelligence Agency; Frederick M. Ruthling, U.S. Air Force; Erik Saar, U.S. Army; Virginia K. Saba, U.S. Public Health Service (retired); Donald E. Shanks, U.S. Marine Corps (retired); Maxwell E. Shauck, U.S. Navy; John R. Sheridan, U.S. Army; Terron Sims, II, U.S. Army; Drew Sloan, U.S. Army; Richard W. Smith, U.S. Marine Corps (retired); Charles White Stockel, U.S. Army; John S. Storm, U.S. Navy (retired); Milton R. Swayze, U.S. Army; Orrie D. Swayzie, U.S. Air Force; Maura Sullivan, U.S. Marine Corps; George R. Thomas, U.S. Navy; George M. Van Sant, U.S. Marine Corps (retired); Kayla Williams, U.S. Army; Thomas R. Zajac, U.S. Army</p> <p>Written testimony: March 24, 2009</p>
UAR	<p>Park Waldroup, University of Arkansas</p> <p>Written testimony: April 14, 2009</p>
UCANR	<p>Glenn Nader, University of California</p> <p>Written testimony: April 21, 2009</p>
UCB	<p>Robert Sawyer, University of California, Berkeley</p> <p>Oral testimony: April 23, 2009</p>
UCD1	<p>Sonia Yeh, UC Davis - Inst. of Transportation,</p> <p>** Duplicate of submission 179SCIENTISTS **</p> <p>Written testimony: April 22, 2009</p>
UCD2	<p>Stephen Kaffka, UC Davis, Department of Plant Sciences</p> <p>Written testimony: April 22, 2009</p>
UCD3	<p>Sonia Yeh, UC Davis, Institute of Transportation Studies</p> <p>Oral testimony: April 23, 2009</p>
UCS1	<p>Chris Carney, Union of Concerned Scientists; Patricia Monahan, Union of Concerned Scientists</p> <p>Written testimony: March 25, 2009</p>
UCS2	<p>Patricia Monahan, Union of Concerned Scientists</p>

	**Duplicate of submission 179SCIENTISTS ** Written testimony: April 21, 2009
UCS3	Patricia Monahan, Union of Concerned Scientists Written testimony: April 22, 2009
UCS5	Patricia Monahan, Union of Concerned Scientists Oral testimony: April 23, 2009
UCSB	Jack Thompson, UCalSB Written testimony: March 16, 2009
UIC1	Steffen Mueller, University of Illinois at Chicago Written testimony: April 15, 2009
UIC2	Steffen Mueller, University of Illinois at Chicago Written testimony: April 15, 2009
UIC3	Kenneth Copenhaver, University of Illinois at Chicago Written testimony: April 7, 2009
UIUC1	Darrel Good, University of Illinois; Scott H. Irwin, University of Illinois Written testimony: April 13, 2009
UIUC2	Hans H Stein, University of Illinois Written testimony: April 14, 2009
UIUC3	Carl Parsons, University of Illinois Written testimony: April 7, 2009
UMN	Jerry Shurson, University of Minnesota Written testimony: March 25, 2009
UMO1	William Sexten, Commercial Agriculture Program Written testimony: April 13, 2009
UMO2	Monty Kerley, University of Missouri Written testimony: March 31, 2009
UNE1	Kenneth Cassman, University of Nebraska; Bill Northey, Iowa Secretary of Agriculture; Mark Stowers, PhD, Poet, LLC; Mark E. Calmes, Archer Daniels Midland; Gerson Santos-Leon, Abengoa Bioenergy; Karen Margrethe Oxenbøll, Novozymes; Bob Dinneen, Renewable Fuels Association; Todd Sneller, Nebraska Ethanol Board; Kelly Brunkhorst, Nebraska Corn Board Written testimony: March 31, 2009
UNE2	Adam Liska, University of Nebraska Written testimony: April 20, 2009
UNICA	Joel Velasco, Brazilian Sugarcane Industry Association; Marcos Jarik, Brazilian Sugarcane Industry Association Written testimony: April 16, 2009
USDGLLC	Mark Cole, US Development Group LLC Written testimony: April 22, 2009
USNAVY1	Randal Friedman, US Navy Written testimony: April 8, 2009
USNAVY2	Randal Friedman, US Navy Written testimony: April 23, 2009

USNAVY3	Randal Friedman, US Navy Oral testimony: April 23, 2009
VALENTE	John Valente Written testimony: April 22, 2009
VALERO	John Braeutigam, Valero Written testimony: April 22, 2009
VANDEL	George Vandel Written testimony: April 20, 2009
VERENIUM	Gregory Luli, Verenium Oral testimony: April 23, 2009
WASTESCT1	Nick Lapis, Californians Against Waste*; Gary Wolff, Alameda Co. Waste Management Authority and Recycling Board; Andy Katz, Breathe California; Julie Muir, California Resource Recovery Association; Scott Smithline, Californians Against Waste; Brian Nowicki, Center for Biological Diversity; Jo Zeintek, City of San Jose, Environmental Services Department; Tim Carmichael, Coalition for Clean Air; Bernadette Del Chiaro, Environment California; Tim O'Connor, Environmental Defense Fund; Danielle Fugere, Friends of the Earth; Simon Mui, Natural Resources Defense Council; Arthur Boone, Northern California Recyclers Associate; David Assmann, San Francisco Department of the Environment; Bill Magavern, Sierra Club California; David Tam, Sustainability, Parks, Recycling and Wildlife Legal Defense Fund (SPRAWLDEF) Written testimony: March 27, 2009
WASTESCT2	Gary Wolff, Alameda Co. Waste Management Authority and Recycling Board; Andy Katz, Breathe California; Julie Muir, California Resource Recovery Association; Scott Smithline, Californians Against Waste; Brian Nowicki, Center for Biological Diversity; Jo Zeintek, City of San Jose, Environmental Services Department; Tim Carmichael, Coalition for Clean Air; Bernadette Del Chiaro, Environment California; Tim O'Connor, Environmental Defense Fund; Danielle Fugere, Friends of the Earth; Simon Mui, Natural Resources Defense Council; Arthur Boone, Northern California Recyclers Associate; David Assmann, San Francisco Department of the Environment; Bill Magavern, Sierra Club California; David Tam, Sustainability, Parks, Recycling and Wildlife Legal Defense Fund (SPRAWLDEF) Written testimony: March 27, 2009
WBIA	Joshua Morby, Wisconsin Bio Industry Alliance Written testimony: April 21, 2009
WD	Rick Souza, Weber Distribution Oral testimony: April 23, 2009
WEITZMAN1	Larry Weitzman, Science (Auto Columnist for Mountain

	Democrat) Oral testimony: April 23, 2009
WEITZMAN2	Larry Weitzman, The Balancing Act Written testimony: April 23, 2009
WG	Kelly McKechnie, Western Growers Oral testimony: April 23, 2009
WHITE	Sharyn White Written testimony: April 2, 2009
WIINC	Jonathon Burke, Westport Innovations Inc. Oral testimony: April 23, 2009
WINNISON1	Robert Winnson Written testimony: April 21, 2009
WINNISON2	Robert Winnson Written testimony: April 22, 2009
WIRA	Craig Moyer, Western Independent Refineries Assoc. Oral testimony: April 23, 2009
WM1	Chuck White, Waste Management; Pete Price, California Natural Gas Vehicle Coalition; Kelly Astor, California Refuse Recycling Council; Karen Keene, California State Association of Counties; Dale Botts, California Waste Association; Frank R. Caponi, P.E., County Sanitation Districts of Los Angeles County; William C. G. Malone, DeKalb County Georgia Sanitation Division; Mary Pitto, Regional Council of Rural Counties; Nancy L. Ewert, P.E., Kern County Waste Management Dept.; Kyra Emanuels Ross, League of California Cities; Ed Repa, Ph.D., National Solid Wastes Management Association, Environmental Programs; Kevin H. Kondru, P.E., OC Waste & Recycling; Anthony M Pelletier, P.E., Republic Services, Inc./West Region; Hans Kernkamp, Riverside County Waste Management Department; Robert B. Gardner, PE, SCS Engineers; John H. Skinner, Ph.D., Solid Waste Association of North America; Paul Yoder, Solid Waste Association of North America, California Chapters; Maria Zannes, Solid Waste Industry for Climate Solutions; Tom Reilly, P.E., Waste Connections, Inc. Written testimony: April 6, 2009
WM2	Charles (Chuck) White, Waste Management Written testimony: April 20, 2009
WM3	Chuck White, Waste Management Oral testimony: April 23, 2009
WSA	Alan Osofsky, Rogers Trucking, West State Alliance Oral testimony: April 23, 2009
WSGM	Joshua Gruen, Western States Goods Movement Oral testimony: April 23, 2009
WSPA1	Cathy Reheis-Boyd, WSPA

	Written testimony: April 21, 2009
WSPA2	Kenneth Manaster*, David R. Farabee, WSPA Written testimony: April 23, 2009
WSPA3	Cathy Reheis-Boyd, WSPA Oral testimony: April 23, 3009
YANG	Kyle Yang Written testimony: March 20, 2009
YOKAYO	Kumar Plocher, Yokayo Biofuels Written testimony: April 22, 2009
YULEX	Bob Epstein, Meera Balakumar, Paul Zorner, Sanjay Wagle, Jeffrey A. Martin Written testimony: April 2, 2009

B. EXTERNAL PEER REVIEWS

The Low Carbon Fuel Standard is based on comprehensive fuel lifecycle GHG assessments and indirect land use change analyses, both of which represent cutting-edge scientific principles in air pollution regulations. In accordance with Health and Safety Code section 57004, which requires ARB and other Cal/EPA boards, departments, and offices to obtain an external scientific peer review of proposed rules and regulations that have a scientific basis or scientific components, ARB obtained the required peer review. Comments were received from four peer reviewers selected by the University of California (UC) and funded with a stipend under an Interagency Agreement between Cal/EPA and UC (IAG #06-104-600-0). The peer reviewers were:

- John M. Reilly, Ph. D., Sloan School of Management, Massachusetts Institute of Technology (MIT)
- Valerie Thomas, Ph.D., School of Industrial and Systems Engineering, Georgia Institute of Technology
- Denise L. Mauzerall, Ph.D., Woodrow Wilson School of Public and International Affairs, Princeton University
- Linsey C. Marr, Ph.D., College of Engineering, Virginia Tech

The purpose of the peer review was to obtain expert analyses of the scientific portions of the proposed rule and to obtain the reviewers' assessment on whether ARB has demonstrated that the scientific portions of the rule are based upon sound scientific knowledge, methods, and practices. Each review was performed independently of the other reviews and without interaction with any ARB staff or other significant contributors to the proposed regulations. The comments are those of each individual reviewer; therefore, the comments do not represent a consensus of the reviewers.

The peer review comments were made available to the ARB and to the public prior to the April 23, 2009 Public Hearing at which the Board approved the LCFS regulation. Based on Board review and direction, none of the comments require major modifications to either the proposed rule or the analysis used to support the proposal. A number of comments identified questions or issues to be further addressed in order to clarify or improve the report. ARB staff has prepared a response to these comments. Given the nature of the peer review, the following includes identification of comments supporting elements of the proposal or supporting documents and accordingly not needing a response.

Response to Peer Review by John M. Reilly, Ph. D., Sloan School of Management, Massachusetts Institute of Technology

B-1. Comment: The greenhouse gas modeling approach, using the GREET model, to calculate direct lifecycle emissions for different emissions pathways is in general appropriate given the nature of the LCS and assuming GHG controls do not exist elsewhere. The emissions coefficients rely on technical work that appears sound. From a technical economic standpoint, however, a far more

efficient approach to regulating GHGs is to put in place an economy wide GHG pricing system, either through a GHG tax or a cap and trade system. This would eliminate the need for lifecycle analysis of the type employed in the GREET model. Since any GHG emission would be priced, the producers of alternative fuels would have an incentive to use less GHG-intensive production methods and to the extent that there were GHG emissions from these processes the prices of these alternative fuels would have embedded in them the GHG cost as producers would have to pass that on to consumers so as to recover costs. This approach to using either quantity or price mechanisms for environmental control is laid out in any standard environmental economic text book as a first best solution to environmental management. Unless specific evidence to the contrary is presented, one should presume approaches that do not match this standard achieve environmental objectives at higher cost. Pricing the GHG consequences of land use change would extend these efficiency characteristics to indirect emissions as well and would then eliminate the need for the development of coefficients for indirect emissions associated with land use change. (See e.g., Reilly and Asadoorian, 2007).

That said there are good reasons why California cannot achieve this ideal and so there is need to consider lifecycle emissions. In particular, an "economy-wide" GHG pricing system in this case would require a fully realized global policy where all countries priced GHG emissions from all sources including land use change. Under a partial system, border adjustments – where alternative fuels are generated by non regulated entities – are likely needed to limit the possibility of leakage. Here I define leakage specifically as an increase in emissions beyond the regulated entities that is spurred by the policy imposed on the regulated entities. (The report defines leakage as a vague concept applied to economic leakage as well – that concept has a shakier foundation as it does not comport with standard economic principles of trade and comparative advantage.) Thus, even if California were to establish an economy-wide cap and trade system to replace the LCFS it would likely be necessary to assess the lifecycle emissions of fuels imported into California to establish an appropriate border price adjustment on these fuels. As the report describes a hope that in devising these regulations California sets a standard for other jurisdictions it seems necessary to investigate the efficiency loss from choosing a third or fourth best policy alternative to that of a first or second best. Acknowledging that the first best – a global economy-wide policy – is not possible at this time it is useful to have in mind how one could transition to such a first best solution. This comment spills over into the economic assessment and "big picture" issues but the various technical economic inefficiencies of the proposed LCS and how that affects technical estimates will be a recurring theme of my comments. (PEERREVIEW2)

Response: The LCFS is a discrete early action item within the broader Assembly Bill 32 program which will include a statewide cap and trade mechanism. AB 32 and Executive Order S-01-07 together establish the process that will lead to the changes suggested. Under AB 32, a cap and trade program is being developed, and once

established, the LCFS will be modified to accommodate interaction between the two programs. Executive Order S-01-07 directed ARB to establish a Low Carbon Fuel Standard for California with the goal to reduce the carbon intensity of California's transportation fuels by at least 10 percent by 2020.

In addition, the LCFS is designed to reduce California's dependence on petroleum, create a lasting market for clean transportation technology, and stimulate the production and use of low-carbon fuels in California. To achieve Governor Schwarzenegger's long term goal of reducing GHG emissions by 80 percent by 2050 (Executive Order S-3-05), the carbon intensity of transportation fuels will need to be substantially decreased over the 2020 target of a 10 percent reduction. The LCFS is structured to stimulate more fundamental changes to the transportation fuel pool, moving towards fuels that meet the much lower carbon intensities needed to meet long-term GHG emissions goals. We do not believe that including fuels in a cap and trade program alone will be sufficient to achieve these goals.

B-2. Comment: An important aspect of the regulations is the ability of Regulated Parties to propose additional pathways or to provide evidence for different values of coefficients to be used in existing pathways. This provides an incentive for Regulated Parties to improve methods of producing alternative fuels or to acquire fuels from sources that use improved methods along each generic pathway. This feature brings some of the efficiency characteristics of the first best solution by incentivizing process improvements that reduce GHG emissions but it requires a bureaucratic review process. As it is formulated, however, a concern is that this incentive process can create adverse selection bias. That is, those Regulated Parties whose production methods for these pathways, produce more GHGs than default values in the pathways developed by the ARB have no incentive to report higher emissions, but those who are below the average can request to use lower values. Thus, one would expect that those who continue to use the default values will have, on average, emissions above the default values. As a result the policy will fall short of its objectives. The extent of this slippage will depend on the variation in emissions from alternative fuel suppliers from the average value. The report should thus investigate not only the average value of emissions along each pathway but also the range. To the extent that a distribution of likely future emissions for each of the pathways could be established the ARB could then estimate how far it would fall short of the LCS goal assuming that those who did better than the average, requested a pathway emissions estimate reflecting their actual emissions, while those that did worse continued to use the default values.

One partial solution to the adverse selection problem is to assign a relatively high value to emissions for each pathway. One would then expect that most Regulated Parties would make a case that their emissions were lower and one would expect many of these to be approved. This process would in most cases force Regulated Parties to reveal the information on their actual emissions to the ARB, reducing the difficult task of the Board to go out and investigate whether the default values are seriously underestimating actual emissions. The

Regulated Parties should be in a position to be relatively information rich on their own practices compared with the Board which would need to inspect and investigate facilities in order to understand how they might differ from an average. In principle, if one had a good estimate of the distribution of emissions along each pathway, the Board could set the default value at a predetermined upper point in the tail, and thereby estimate how much they would likely miss the actual target by setting it at 1 standard deviation above the average, or at the 10 or 5 percent tail. The nominal LCS could then be tightened to take account of estimated slippage.

One also needs to be concerned about the incentives created that might increase emissions associated with these alternative fuels pathways. If it becomes less expensive along a given pathway to produce fuels in a different manner that results in greater emissions, then there will be an incentive to alter the process in that way as long as the process is not altered so much as to clearly be a "different" pathway. For example, suppose natural gas becomes expensive and is supplemented somewhere in the world with syn-gas produced from coal; or transportation of the alternative fuel to California relies increasingly on fuels produced from oil sands or heavy fuels. Without a complete trace of these alternatives outside the California system, alternative fuels produced in this manner would continue to look like the default pathway. However, actual lifecycle emissions would be higher than the default and this might then disadvantage California producers of alternative fuels who were subject to emissions controls on fuels used within the state, and therefore would not have an economic advantage to using these dirtier alternatives.

Clearly, another way to minimize adverse selection effects is to define a very large number of pathways with slightly different coefficients to meet ever finer ranges of production processes but that would place an ever greater burden on the Board. In contrast, setting the emissions at the high end creates an incentive for the Regulated Parties to produce pathways and reveal information that the Board can then assess. The potential behavioral response to changing incentives is more difficult to incentivize in the California system, short of regular investigation by the Board of possible changes and updating of the default values. These efficiency issues are created by choice of a third or fourth best control instrument and speak to the value of working toward a first best control approach. (PEERREVIEW2)

Response: The LCFS does not use single default carbon intensity values for alternative fuels. For most alternative fuels, we have produced a number of individual pathways that differ based on major production process variables. Regulated parties must use the carbon intensity value that corresponds to the pathway that best represents their production process. Moreover, the carbon intensity value selected by the regulated party is subject to approval by the Executive Officer. If no pathway in the Lookup Table closely represents the fuel production process used by the Regulated Party, Method 2A or Method 2B can be used to generate a new, more representative

pathway. Therefore, we believe that the inclusion of multiple pathways in the Lookup Table, the stipulation that the selection of a carbon intensity value is subject to Executive Officer approval and the flexibility to generate new pathways using Methods 2A and 2B will result in an accurate representation of the carbon intensity for alternative fuels subject to the LCFS.

For the baseline fuels, the lookup table sets forth single total CARBOB and diesel fuel carbon intensity values covering crude production, refining, use of the fuel, and all transportation and distribution activities. The carbon intensity values are based on the average crude oil delivered to California refineries in 2006, and the average California refinery efficiencies in 2006 (2006 was the last year for which data were available). With the exception of high carbon intensity crude oils not part of the 2006 California baseline crude mix, regulated parties must use these single carbon intensity values for all California CARBOB and diesel fuel regardless of the actual carbon intensity of producing or transporting the specific crude oil used, or the specific refinery operations. This approach is taken to reduce the incentive for regulated parties to comply with the LCFS by shifting to less carbon-intensive crude oils or refinery operations. Use of less carbon intensive crude oils would likely do nothing to reduce global GHG emissions because the higher carbon-intensive crude oils replaced would be refined and used elsewhere. California refineries and large oil extraction operations will be subject to the upcoming AB 32 cap and trade program, so any reductions in GHG emissions from these activities will be counted in that program. The objective of the LCFS program is to stimulate more fundamental changes to the transportation fuel pool, moving towards fuels that meet the much lower carbon intensities needed to meet long-term GHG emissions goals. This objective is best served by identifying single carbon intensity values for almost all CARBOB and diesel fuel, and not allowing revised pathways to be established under Method 2A for CARBOB and diesel fuel with lower carbon intensities.

B-3. Comment: Another question I have with regard to the greenhouse gas modeling that is somewhat related to the above issue are the electricity pathways. At several points in the document the report expresses the idea that there is sufficient electricity capacity to meet the demand for these electric vehicles because of idle capacity. The suggestion is that households would choose to recharge overnight and during off-peak hours when there is idle capacity. The situation may be different in California but in many parts of the country the baseload generation is coal-fired power plants that ideally would be run through the night, and utilities could then time of day price to encourage more effective use of this low cost base-load capacity. However, if this baseload capacity is heavily based on coal it is likely more carbon intensive than the average mix. If the goal is to use idle baseload capacity then the "marginal electricity mix of natural gas and renewables" is mostly not relevant unless perhaps, some renewable such as wind, is not well matched to current power demand peaks and it is hoped that energy produced from such sources can actually be useful because one now has the capacity to shift the recharging demand to periods when these sources are available. However, unless one has a very persistent diurnal pattern it would seem difficult to take advantage of a lot of the variability in

renewables since at best the recharging can be shifted around by some hours within the day but not over seasons, since these vehicles will need to be recharged on a daily basis. Thus, similar to using relatively high emissions coefficients for other pathways, it would seem that the default pathway for electricity should assume the average GHG coefficient of baseload power, and regulated entities could make the case for lower emissions where they can document that indeed something other than baseload power is being used. Otherwise I find that the discussion of this goal of using existing off-peak capacity is inconsistent with the defined pathways that assume average emissions or lower carbon "marginal" additions to the system. (PEERREVIEW2)

Response: In California, baseload electricity is heavily weighted toward low GHG emission sources such as nuclear, hydroelectric, geothermal and biomass. Unlike the Midwest, coal contributes only 15 percent of the California average electricity mix and therefore will contribute much less than half of the baseload capacity. Therefore, we do not believe that the carbon intensity of baseload electricity will differ significantly from average.

We agree with the comment that if vehicles are predominantly charged overnight, the appropriate carbon intensity would be that of baseload electricity. If, however, vehicles are charged throughout the day and night as needed, the use of average electricity may be more appropriate. In the absence of direct metering to record electricity consumption as a function of time of day, we believe that use of the average electricity mix is appropriate. By January 1, 2015 all electricity receiving credit under the LCFS must be dispensed using direct metering. Direct metering will allow for the application of carbon intensity values which vary as the overall resource electricity mix changes with time of day.

B-4. Comment: Also at issue with PHEVs are the incentives, or lack thereof, in these standards to use them predominantly on their all electric range. The PHEV pathway must make some assumption about the proportion of time the vehicle will be run on the electric versus the internal combustion engine. Ideally a GHG control policy would create incentives for drivers to use the vehicle in battery mode as much as possible. As far as I can tell, there will be an assumption of this embedded in the GREET pathway that may or may not be accurate. Since there is no experience with how PHEV owners might actually use their vehicles this seems speculative. Again, a first best solution that priced GHGs in fuel would further encourage drivers toward short trips, and recharging more frequently to avoid using the vehicle beyond its all electric range. Since many drivers place a high value on convenience (i.e. their time) if recharging is slow or facilities inconveniently located owners may rely much more on the internal combustion engine of the PHEV. In the LCS approach to regulation this will result in the target reduction being exceeded. In a cap and trade system, if this fuel is sold it will necessitate reductions elsewhere to meet the cap and the desired cap will be met. Again, an inefficiency of using a third or fourth best alternative. (PEERREVIEW2)

Response: The LCFS does not include a PHEV pathway but rather includes separate electricity and gasoline pathways. By January 1, 2015 all electricity receiving credit under the LCFS must be dispensed using direct metering. Therefore, regulated parties receiving credit for electricity use by PHEVs will simply report the amount of electricity dispensed by these charging stations. No assumption about the proportion of time the vehicle is run on electric versus internal combustion is required. Furthermore, requiring electricity to be dispensed by direct metering in order to receive credit under the LCFS provides an incentive for regulated parties to conveniently locate vehicle charging stations in order to capitalize on this market. Convenient location of charging stations will encourage relatively greater electricity use by PHEV owners. Fueling at night or during off peak hours can be easily incentivized by charging lower rates for off peak charging. The use of direct metering should enable this.

B-5. Comment: The indirect emissions issue identified in the report is an important topic and as the report identifies it is the biofuels alternative where current research has shown this to be most important. As the report indicates this is a very new area where research that could establish with confidence such indirect emissions is in its infancy. Ideally one would want to like to have had the scientific community investigate these issues and to have published competing estimates, resolving among them better or worse approaches and identifying uncertainties. The work developed in this report to estimate these indirect emissions is far beyond anything else that has been done in this regard. However, since there is virtually nothing else out there that is comparable it is difficult to determine how accurate these estimates are. The nature of the problem is that it requires a full model of the global economic system to separate out the partial effect of increased demand for biofuels on land use change, and this requirement is recognized in the report. The report accurately describes how any direct empirical evidence from recent changes in biofuels production, corn and soybean exports, and land use change are highly confounded by simultaneous changes in demand abroad for other purposes and possible supply-side shocks.

Since the evidence is that there are likely land use implications of biofuels expansion, my judgment coincides with that expressed in the report, that including an estimate of these indirect emissions is better than leaving this emissions source out completely because of uncertainty. Elsewhere I expressed the view that using a relatively high value, and allowing Regulated Parties to provide evidence for lower values, would create incentives to reveal actual emissions as they vary among actual pathways of different parties and to avoid adverse selection. For the most part the indirect emissions along a particular pathway would seem to be less likely to vary by Regulated Party using the pathway – the indirect emissions are the result of the interaction of global markets in response to, e.g. more use of corn for ethanol – which would be common for any Regulated Party using that pathway. (Although with different trade elasticities and such, the source of biomass feedstock could result in

different indirect emissions.) Thus, it is less clear to me that choosing an average coefficient will lead to adverse selection and the likelihood that the LCS goals will not be met. (PEERREVIEW2)

Response: Thank you for the supporting comment. The Board acknowledged in Resolution 09-31 that the available methods for estimating indirect impacts (including land use change) are relatively new. As they continue to undergo development, the uncertainty associated with the impact estimates from these methods will decrease. In recognition of the relative infancy of the LUC analysis, the Board directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. The Board will consider the findings of the workgroup in its continuing efforts to improve the LUC assessment. In approving the LCFS, however, the Board found that current uncertainty levels are not sufficient to call into question the existence of significant indirect land use change impacts.

B-6. Comment: The yield response that is modeled and that then reduces the amount of converted land (and indirect emissions from land use change) is a process of intensification of production on existing land. The process of intensification generally involves using more inputs as a substitute for land. The intensification process likely involves increases in GHG emissions. Some of the most substantial aspects of intensification are likely to be increased use of fertilizer, especially nitrogen, increased irrigation, and denser livestock management. Increased use of nitrogen would lead to increased emissions of N₂O, a potent greenhouse gas. This increase in nitrogen is on intensified conventional agricultural land and is a further indirect effect of biofuels expansion. The report identifies water use as an issue. However, in addition to water issues themselves, water use has GHG implications. Pumping of groundwater is relatively energy intensive and to the extent surface water is diverted for irrigation, limiting hydropower production, there are likely GHG implications of producing that power with alternatives that are likely to include some mix of fossil fuel generation sources. Intensive livestock management is often associated with confined livestock facilities and manure management practices that result in methane emissions, another potent GHG.

Intensification may also result in increased carbon stores in soils, especially if it results in land improvements on low productivity or lands degraded from use in grazing and pasture. Generally increased fertilizer and water use can greatly increase the amount of biomass produced on low fertility or water limited land, and even with removal of the harvested portion of the crop the biomass left behind can greatly increase the soil carbon. It is hard to judge how important these may be and they are highly variable depending on exactly what land is being used (see e.g. Reilly et al, 2006) but these issues at least worth investigating. Again, a first best solution that was pricing emissions throughout the economy would avoid the need to assess these. (PEERREVIEW2)

Response: ARB is committed to an accurate accounting of carbon intensity values for all fuels. The Board continues to evaluate these and other indirect effects with intent of quantifying and incorporating all significant direct and indirect emissions. Furthermore, the Board has directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. Intensification of farming practices will likely be a topic evaluated by this workgroup.

B-7. Comment: The report concludes that there are likely no land use implications of use of waste materials such as fats and oils or of corn stover. For true waste materials - fats and oils from food preparation that would otherwise be disposed of - that is probably true. However, most fat and oils from the meat industry, for example, are used in feed and food production and are consumed. If they were redirected to biofuels production, then other products such as soybean or corn oil would need to be used in place of them with potential land use and GHG implications. Similarly, waste biomass such as corn stover has in some cases other uses (livestock bedding) that would need to be replaced and if not and it is left in the field it is a carbon source that remains out of the atmosphere for some time and contributes to soil carbon levels. If that source of carbon replenishment of the soil is systematically removed, then soil carbon stocks will fall, contributing to increases in atmospheric carbon. Organic matter is also a source of nitrogen and it typically releases nitrogen more gradually than inorganic sources and in tune with regrowing plants and thus emits less N₂O than would applications of commercial fertilizer. Thus, higher N₂O emissions with increased fertilizer use required because of removal of corn stover (or similar agricultural waste) is a likely additional indirect effect. (PEERREVIEW2)

Response: The current pathway assessments for biodiesel from used cooking oil and for renewable diesel from tallow do assume that the used cooking oil and tallow are truly waste materials. If this is not the case for a producer, then a new pathway will be developed in which the indirect effects associated with feedstock replacement must be included.

B-8. Comment: Comments above about indirect emissions coefficients addressed indirectly some of the land use modeling issues. In general, the developments made in the Report on modeling land use/agriculture and indirect emissions have advanced this area of research. Thus, the ARB in investigating this area is at the state-of-the art. As noted above, and by the ARB Report this field is in its infancy. The analysis in the Report does an admirable job of testing the sensitivity of results to key parameters. More important than parametric uncertainty, however, may be structural uncertainty. Gurgel et al. 2007 and Antoine et al. 2008 find big differences in land use response depending on the structure of the model. The GTAP model approach is heavily conditioned on a relatively short run response to marginal changes. It is probably appropriate for an LCS operating in limited jurisdictions (e.g. California) with a time horizon of 15 years. Unfortunately, climate change is a global problem that requires management over many decades to centuries. Much more investigation is thus

needed to see whether the properties of this regulatory regime have any value over the longer time span and when expanded to enough jurisdictions so that it would actually have a noticeable affect on slowing climate change. It is well accepted in empirical economics that there are many short run irreversibilities that lead to elasticities of response to be smaller in the short run than in the long run. As Gurgel et al (2007, 2008) argue, these elasticities are highly simplified representations of other structural element of the system. Some issues: observations on land conversion elasticities may reflect short term rigidities, and often price pressures do not persist for decades. If biofuels expansion occurs broadly and globally, the price pressure to convert could persist over many decades at levels well beyond recent observations rendering elasticities based on observation questionable. On the other hand, if "demand" for unconverted land grows with income and that demand is expressed by protecting more land either through private or public ownership, this factor may more than offset pressure from biofuels development (see, Gurgel et al., 2008). Armington trade elasticities are also suspect. While highly used, it is not hard to generate hard to explain divergence in regional prices when differential pressures exist over the long term. Thus, sector prices that are 2, 3, or 5 times higher in one region than another can easily develop with Armington specifications. While an explanation for price divergence can be differences in the "product" of the sector in each country – US automobiles differ from German or Japanese automobiles – it is still hard to justify large price gaps beyond those that already exist because of the mix of vehicles. The problem is even greater for more homogenous bulk commodities such as corn. Evidence on trade elasticities inevitably reflect longer term contracts and relationships, existing shipment and production capacities, and other short run irreversibilities which in the long are reversible.

The trade elasticity issue may not show up as important in this analysis because as far as I can tell the analysis alters the land conversion elasticities but uses a common elasticity worldwide, thus it matter less where the crop is produced because one gets that same land response in all regions. This poorly reflects observation which shows greater willingness to convert land in the tropics than in the developed countries in temperate regions. Some estimates of this differential are reported in Gurgel et al. (2007) and also remain when the elasticity concept is replaced by an explicit recreation demand for land which varies by income as in Gurgel et al. (2008). It may thus be important to consider varying this elasticity by region as that could effect the relative indirect emissions of sugarcane versus corn ethanol, for example. (PEERREVIEW2)

Response: We acknowledge that the sensitivity analyses performed on the GTAP model runs were abbreviated and that many issues related to elasticity values used in the analysis were not thoroughly investigated. Formal sensitivity analyses, leading to probability and uncertainty distributions were not performed. These were not possible given the time and resource constraints under which the LCFS land use change team worked. In recognition of this, and other sources of uncertainty summarized in this comment, the Board adopted a conservative (low) land use change carbon intensity

increment for corn and sugarcane ethanol, and directed staff in Resolution 09-31 to form an Expert Workgroup to continue studying the land use change phenomenon, and the available approaches to measuring it. We expect this workgroup to take up the issues of sensitivity and uncertainty analysis.

B-9. Comment: The highly aggregated carbon coefficients associated with land use change are also a major weak spot in the analysis. Mellilo et al. (2009) embed the Terrestrial Ecosystem Model into a general equilibrium model to more accurately compute indirect carbon and nitrogen implications of land use change and thereby likely better capture the regional variation in carbon stocks on different types of land and the changes in carbon stocks on the intensive margin due to intensification. That said, this work looks only at a single biofuel derived from cellulosic material and the published material does not report the nitrogen impacts but it points the direction this work must head. (PEERREVIEW2)

Response: Although based on the best currently available empirical data, emissions factors are averaged over extensive geographical areas. Emission factors specific to smaller geographic areas would be preferable. As improved factors meeting these requirements become available, ARB will base its land use change emissions estimates on those factors. ARB staff is convening an Expert Workgroup to consider possible approaches to improving its land use change estimates. Emission factors will likely be a topic evaluated by this workgroup.

B-10. Comment: Finally, the time profile of emissions from land use change and biofuels is a very thorny issue. Herzog, et al. (2003) address some aspects of this for leakage from ocean storage and the issue of gradual emissions from land use has some similarities, and Reilly and Asadoorian (2007) discuss additional aspects of how to address this issue for land use change. The problem confronted here is that there are emissions from land use change in the near term that with a long enough horizon will eventually be more than made up by the fossil fuel offset from using biofuels. Again, a first best solution, an economy-wide cap on all emissions including those from land use change would address this issue. The cap would be set to reach a desired concentration target. Thus, ignoring uncertainty in natural system response, that target would be met. If it made economic sense, given full GHG pricing, to deforest and release carbon, the broad cap would ensure that such releases would need to be met by larger reductions from other sources, and given that differences in timing of reductions were appropriately reflected in banking and borrowing rules the system would take care of itself. This does require the banking/borrowing rates which would need to reflect the time path of damage but as default value, I believe it is reasonable to consider that the marginal damage of emissions and different points in time as equal. One reason is that the lifetimes of most gases are so long that there is a large overlap in terms of damages from emissions at different times. And absent much knowledge on where tipping points and irreversibilities exist in the system, and what they are, it seems as likely that we will cross some of these at almost any concentration. The climate risk has sometimes been

described as a problem of future generations suggesting marginal damages will be higher in the future. The new evidence suggests some of those tipping points may be much more immediate and so the view that marginal damages of near emissions is relatively low is probably inaccurate. I don't have a good way to convert this logic into coefficients such as a Fuel Warming Potential. However, my intuition is that the FWP is a deeply flawed concept, much more so than the Global Warming Potential indices used to compare GHGs. (On GWP's see e.g. Reilly and Richards, 1993) (PEERREVIEW2)

Response: Executive Order S-01-07 directed ARB to establish a Low Carbon Fuel Standard for California with the goal to reduce the carbon intensity of California's transportation fuels by at least 10 percent by 2020. The LCFS is a discrete early action measure within the broader Assembly Bill 32 program which will include a statewide cap and trade mechanism. AB 32 and Executive Order S-01-07 place bounds on the requirements for and design of our program and preclude the broader structural changes suggested in this comment.

We agree with the assessment that the marginal damages of emissions do not likely not change appreciably with time. However, we have not concluded that the FWP method of time accounting is a deeply flawed concept. An article based on this method was recently published in a peer reviewed journal and therefore the method has received some scrutiny by the scientific community.³ The FWP method will also likely be a topic of discussion for the Expert Workgroup which is being convened at the Boards direction to further evaluate the estimation of land use change emissions. We will continue to evaluate the FWP method and consider input from the scientific community and the Expert Workgroup on this matter.

B-11. Comment: The economic analysis assumes that current tax and subsidy policies remain unchanged. The implication of this is that Californians will bear no responsibility for the tax expenditures created by these subsidies. In general, the correct principle for estimating economic impacts is to assume revenue neutrality. That is, increased tax expenditure on subsidies must be made up for with increased taxes elsewhere. And similarly, increased tax collections are made up for with decreased tax rates, leaving the level of service provided by the tax collection unchanged. For a neutral assumption, Californians should bear the full cost of tax expenditures on subsidies, and these expenditures (along with tax collection costs) should be included as implementation costs in the analysis. (PEERREVIEW2)

Response: We recognize that it is appropriate to include tax credits in the economic analysis, as this analysis was done on a cost-of-compliance basis – which is an analysis that is consistent with other ARB regulations – not on a social basis. Congress has chosen to create tax credits for alternative fuels in order to promote their

³ O'Hare, M.; Plevin, R.J.; Martin, J.I.; Jones, A.D.; Kendall, A.; Hopson, E. (2009) Proper accounting for time increases crop-based biofuels' greenhouse gas deficit versus petroleum. Environmental Research Letters, 4.

commercialization and make them more competitive with traditional transportation fuels. It is appropriate to assume these credits will be extended beyond current expiration dates because this has historically been the case and the cost-competitiveness goal for biofuels has not yet been achieved. If a cost analysis was conducted on a broader, social basis, the tax credits would not apply and cost neutrality would occur.

B-12. Comment: Tax collectors should be notified of the tax implications of implementing the LCFS so that administrators and elected officials can decide if these revenue impacts are addressed with changes in the level of service provided or in the tax rate. (PEERREVIEW2)

Response: It is appropriate to notify elected officials of potential tax revenue impacts so that they can make decisions regarding tax-rate revisions. Staff determined the fiscal impact of the LCFS on State and local governments, as required by Government Code Section 11346.5, and on the federal government and included this information in Chapter VIII of the ISOR.

B-13. Comment: Another critical issue is the accounting of only fuel and administrative costs and not of vehicle costs. On the one hand I can see the rationale of not accounting the PHEV vehicle if a pre-existing ZEV program is requiring this level of PHEVs anyway. The cost then really accrues to the ZEV policy rather than the LCFS policy. However, since the LCFS program is being touted as a model for other jurisdictions that do not have a ZEV program, it would be useful to estimate the cost of the PHEVs. I also did not see discussion of the increases in the cost of vehicles to include flex fuel capacity. This is a relatively small cost per vehicle as I understand it but should not be ignored. (PEERREVIEW2)

Response: The cost of specialized vehicles should not be included in the economic analysis for the LCFS because the LCFS does not mandate deployment of these vehicles. Although the five gasoline and three diesel illustrative compliance scenarios included varying numbers of specialized vehicles, that analysis was conducted on a “what if” basis. What if there were one million ZEVs, or two million ZEVs? The possible low-carbon fuel scenarios included options where the fuels mix satisfied the vehicle assumptions. The vehicles are not mandated.

Additional zero emission vehicles (e.g., battery electric vehicles, plug-in hybrids, fuel cell vehicles) may occur through additional mandates by the Board or consumer preferences. If California mandates the development of additional ZEVs, the costs and economic impacts of those vehicles would be borne by the ZEV program, not the LCFS.

Regarding flexible fuel vehicles (FFVs), the federal RFS2 will bring more than three billion gallons of ethanol to California, with or without the LCFS. This volume will determine the need for E85 and the number of FFVs in the State. Since the LCFS requires no greater total volume of ethanol than RFS2, the marginal cost of FFVs should not be attributed to the LCFS. The marginal cost of FFVs is modest. Estimates

on page 48 of Appendix F of the ISOR show that the marginal cost of producing an FFV is \$200 above a comparable gasoline powered vehicle.

B-14. Comment: If we take the analysis on face value that specialized vehicles will exist anyway and that with existing subsidies these options are actually less expensive than conventional fuel then the drivers in the State should adopt these alternative fuels without the LCFS. In fact, it is not clear why they would stop at just meeting the LCFS goals and not substitute these fuels completely based on the assumptions in the report. Some logic needs to connect the idea that with subsidies these alternative fuels are so inexpensive that they will save consumers money, yet there is still a need for the LCFS. (PEERREVIEW2)

Response: The purpose of the subsidies is to make alternative fuels competitive with traditional transportation fuels. The adoption of an LCFS will expedite and reward the commercialization of lower-CI fuels, making them competitive more quickly than if no regulation were in place. Earlier commercialization of lower-CI fuels is essential for California to meet the GHG reductions targets in the AB 32 Scoping Plan and Executive Order S-01-07.

B-15. Comment: I understand the argument presented as to why the LCS does not fall under a change in fuel specifications and therefore does not, in the opinion, of the ARB lead to full multimedia environmental impact assessment. Whether that holds is likely a legal issue and it is beyond my competence to comment on. The small potential benefits of reduced particulate matter associated with biodiesel seem reasonable. However, I don't see why these are computed when other potential changes in fuels are not considered based on the fuel specifications argument. Perhaps I don't fully understand this issue, but computing these seem to open the door for asking why not consider the possible changes in volatility of the gasoline stock with changes in ethanol blending, or the potential changes in emissions of NOx, CO, etc. If this is clear to others in the context of California then perhaps the report is fine but it appears that the report has cherry-picked some potential benefits and ignored other changes that might have been negative. (PEERREVIEW2)

Response: The ARB has a long history of regulating motor vehicle fuel properties. The CaRFG regulations establish specifications for and properties of gasoline and a predictive model to allow fuel producers to adjust the properties within defined caps and still preserve the benefits of the regulations. This includes adjusting for the impact of ethanol on evaporative emissions. The ARB diesel regulations also allow for establishing equivalent alternative formulations compared to the specifications in the regulations. Insufficient emissions data existed to establish specifications for biodiesel that would improve or preserve the benefits of CARB diesel. The ARB has established a test program to provide this information and the Board is scheduled to consider specifications for biodiesel in 2010. A multimedia evaluation for biodiesel is underway and is also scheduled to be completed in this time frame.

B-16. Comment: The sustainability issues....which I interpret to be the broader environmental consequences of biofuels and land use change such as water quality, ecosystem loss, biodiversity changes, etc. are a potential long term concern. It is good that the Board plans to place some attention on these in the future. I can understand why these were not addressed in this Report given the time frame and the complexity of these issues. Melillo et al. (2009) discuss some of these issues. (PEERREVIEW2)

Response: Along the lines of this comment, the Board has directed staff to work with state agencies, interested stakeholders, etc. to present a work plan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation.

B-17. Comment: The credit trading provision offers a cost saving flexibility mechanism but the efficiency characteristics of this mechanism in achieving GHG reductions do not match that of a broad carbon cap and trade system for the many reasons I have laid out in the comments above. The ARB plans to not allow allowances from outside the system to be brought into the system because they interpret the goal of the LCS to be to meet the particular fuel standard, and to purchase allowances from other carbon trading systems would allow the LCS target reduction to be violated. This narrow interpretation has some narrow logic that seems hard to justify from a broader context. Clearly, the main intent of the LCS is to reduce GHG emissions. The entire implementation plan is based on that premise, carefully addressing lifecycle emissions wherever they occur including indirect emissions that go well beyond direct lifecycle emissions and regardless of whether California has direct jurisdiction for them. Yet a certified reduction in greenhouse gases through some other program cannot be credited. If we can save a forest or reforest through CDM, why is that forest carbon different than that avoided by correctly accounting for indirect land use emissions of fuel production? I guess the premise is that there is some unique barrier to low carbon fuel development that needs to be overcome and so a certain LCS standard will accomplish that. It's hard to see that diverse alternative fuels such as electricity and electric vehicles, cellulosic ethanol, and conventional sugar and corn ethanol face similar barriers so that the LCS works efficiently to overcome these barriers in each of these fuels. Existing R&D and demonstration efforts, while probably far from perfect, seem more likely to address different barriers that exist across these diverse fuels. Thus, I see little rational for separating the LCS from a broader GHG market. And, I see little rational for fashioning an LCS that has poorer efficiency properties than a broad cap and trade program. This may go beyond the ARB authority given California legislative direction. However, since the stated intent of this is to create a model program for other jurisdictions it seems appropriate for analysis to compare this third or fourth best policy design with a first best solution. A proper economic analysis would contrast the cost of implementing this system with that of at least the second best system, where California has a broad cap and trade system including transportation and applies

border taxes to account for emissions from fuels imported from jurisdictions without GHG policies. (PEERREVIEW2)

Response: The Board agrees that the LCFS needs to be assessed in light of other options. The Board did this by including the LCFS as part of the AB 32 Scoping Plan. The Board expects other agencies to do the same assessment and is not advocating the proposed LCFS be pursued as a stand alone program in other jurisdictions. See also response to comment B-1.

B-18. Comment: I am concerned that California proposes this inefficiency approach as a model for other jurisdictions and that the analysis in this report fails to demonstrate the inefficient nature of this proposed policy. The Report loosely describes the LCS as complementary to other policies in California that are aimed at GHG reduction. In what sense are they complementary or are they competing, redundant, or unnecessarily increasing the cost of GHG reduction in the State. If this language is to be used a careful technical definition of the word complementary is needed and technical analysis that analyzes and provides support for that conclusion is needed. I see no such analysis in this report. (PEERREVIEW2)

Response: The LCFS is considered complementary to other policies in California aimed at GHG reduction for several reasons. First, the LCFS is part of a much larger policy, AB 32, which aims to reduce GHGs by 80% by 2050. The LCFS complements other policies by helping reach the overall goal. Second, as was pointed out in the Executive Summary of the ISOR, transportation accounts for almost 40% of the GHG emissions in the state of California. There are three ways to reduce these emissions including increasing vehicle efficiency, reducing the number of vehicle miles traveled, and finally reducing the carbon intensity of the fuel used to power the vehicles. Support on the complementary nature of the LCFS to AB 32 can be found in the Scoping Plan which details how all of the policies under AB 32 work to achieve the goal. Any other region considering an LCFS should only consider it as a part of a broader program.

B-19. Comment: There is some solid technical work underlying parts of this report, however, in putting together these technical pieces several problems arise. The economic analysis was done incorrectly. It does not meet technical standards of economics. The baseline assumptions are mutually inconsistent, and if these assumptions were executed in a proper model it would show that the LCS was unnecessary. (PEERREVIEW2)

Response: This comment addresses a broader issue with the LCFS. In his report, Dr Reilly indicated that more extensive economic analyses of other approaches for reducing greenhouse gases from vehicles and fuels, such as carbon fees and cap-and-trade program, should be conducted prior to other jurisdiction adopting an LCFS. He further commented that such an assessment would likely show that an LCFS was a more costly method to reduce greenhouse gas (GHG) emissions than other more economically efficient approaches. The Board agrees with Dr. Reilly's opinion that the

LCFS needs to be assessed in light of other options. The Board did this by including the LCFS as part of the AB 32 Scoping Plan. The Board expects other agencies to do the same assessment and is not advocating the proposed LCFS be pursued as a stand alone program in other jurisdictions.

B-20. Comment: The good technical work on lifecycle emissions and indirect emissions will be useful to policy development in this area, and it appears that much of the effort was devoted to that aspect of the Report. However, in spending much effort on these pieces apparently little effort was devoted to properly bringing these pieces together. While the report recognizes the need for a broad systems model for indirect emissions and sought the GTAP model, it failed to realize that many of these systems issues affect fuel markets and choice of fuels, and thus such a model is needed of fuels and fuel choices. With such a model the logical inconsistencies in the report would have been obvious because once introduced into the model they would have been demonstrated. (PEERREVIEW2)

Response: This regulation is not a volume mandate and the fuel and fuel choices are based on market responses to the cost and availability of the fuel and vehicle technology. We believe the regulation is sending correct signals to the market that biofuels made from food crops are not going to ultimately get us to the end goal. To this point, the addition of indirect effects to fuel carbon intensities will help spur innovation for fuels derived from renewable sources, thus providing more fuel choices and diversifying the fuel pool.

Response to Peer Review by Valerie Thomas, Ph.D. of Georgia Institute of Technology

B-21. Comment: The description in the text of the greenhouse gas impacts of corn-derived and sugarcane-derived ethanol is solid, and could be emphasized more prominently: "Direct GHG emissions from the production and use of corn and sugarcane ethanol are less than the comparable emissions from gasoline. When land use change emissions are considered, however, the emissions-reduction benefit from corn and sugarcane ethanol is diminished." (p. IV-42) (PEERREVIEW3)

Response: No response needed.

B-22. Comment: The lookup table values for carbon intensity for the three gasoline fuels appear to be well justified. (PEERREVIEW3)

Response: No response needed.

B-23. Comment: The evaluation of carbon intensity for eleven different corn-derived ethanol is sound practice and provides a basis for encouraging low-carbon production of corn-derived ethanol. (PEERREVIEW3)

Response: No response needed.

B-24. Comment: The numerical values assigned to the GHG emissions from production of corn-derived and sugarcane-derived ethanol have some uncertainties that could be reduced through revised analysis and further reduced when more data become available.

The calculation of the direct GHG emissions from production of corn-derived and sugarcane-derived ethanol is by-and-large solid and consistent with a well-developed body of scientific research. The calculation of the coproduct credits does, in my view, somewhat overvalue these credits, resulting in an under estimate of the direct GHG impacts of corn-derived ethanol of perhaps 10%.

p. IV-12. Coproduct allocation. Coproduct credits for corn ethanol are allocated in GREET by assuming that the use of coproducts as animal feed results in decreased production of the displaced feed in exactly the amount that is displaced. This effectively assumes completely inelastic demand for the displaced product. This is not consistent with the land use change calculations, which do assume demand elasticities. In other words, the coproduct calculation appears to be overestimated, resulting in a somewhat lower calculation of the direct GHG impact than is probably likely, and indicating uncertainty in the direct emissions results for corn ethanol of at least several percent.

p. C-54. Co-product credit for DDGS. The decision of ARB to not adopt Wang's findings on this issue is solid. However, there is an additional co-product credit issue. In GREET, when a coproduct is used instead of the substitute product, the reduced use of the substitute is assumed to result in exactly that amount of decreased production of that product. This is surely an overestimate, resulting in a small underestimate of the direct GHG impacts of corn-derived ethanol.
(PEERREVIEW3)

Response: ARB has received comments from several stakeholders suggesting that a co-product credit equating 1 lb. of DDGS to 1 lb. of feed corn either overestimates or underestimates the true market response. As discussed in Appendix C of the ISOR, we believe that DDGS faces many limitations as a replacement for corn and soybean meal and the credit allocated in the modeling is appropriate. Moreover, the Board directed ARB staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. Evaluation of co-product credits will be a topic for this workgroup.

B-25. Comment: Taken as a whole, the scientific portion of the proposed rule is based upon sound scientific knowledge, methods and practices. Use of a non-zero positive value for the carbon intensity due to land use change for ethanol from corn and sugarcane is sound. The direct emission values for ethanol from corn and sugarcane, and the differences in direct carbon intensity values for different ethanol production processes are sound. However, the values used to quantify

the carbon intensity due to land use change for ethanol from corn and sugarcane are not yet sufficiently developed to be scientifically confirmed; refinement and validation of those quantities is needed.

The calculation of the indirect, land-use-change GHG emissions from production of corn-derived and cane-derived ethanol has significant uncertainties.
(PEERREVIEW3)

Response: We agree with this assessment. In response to this uncertainty, the Board directed ARB staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. In approving the LCFS, however, the Board found that current uncertainty levels are not sufficient to call into question the existence of significant indirect land use change impacts.

B-26. Comment: That observed data have not been used to validate the GTAP model findings is a significant weakness. The changes in corn production resulting from the federal renewable fuel standard, and the changes in Brazilian sugar production resulting from increased ethanol production should be measurable, and should be measured to validate the model assumptions. The ARB model should be adjusted to reflect data.

The greenhouse gas impact of land use change occurs mainly at the time of land clearing. This suggests that the effect of increased use of corn for ethanol will depend on whether and when total global corn production increases. An increase in use of corn for ethanol in a year in which corn demand decreases or stays constant will have a different greenhouse gas effect than in a year in which total corn demand increases. The increased use of corn for ethanol in one year can result in land clearing in a future year, depending on overall global total corn production and production of other crops. The ARB staff has put a great deal of effort in to thinking about the time dimension of this problem. Nevertheless, time-related issues are still addressed in a piecemeal way that makes some unjustified assumptions. A more comprehensive approach to the changes in corn production over time would be simpler and could be more accurate. ARB could develop a more data driven and less model-dependent approach by observing and tracking changes in land use patterns that have been observed to date and that will be observed over the next few years as corn-derived and cane-derived ethanol production increases.

p. IV-31. It should be possible to validate with data the projections of land use change shown in Table IV-10, and especially the projections of US land use change.

p. IV-39. Comparison of GTAP results with Observed Market Behavior. The effects of corn ethanol on land use either are, or are not, large enough to be observable. As this section states, there are many factors that influence corn production and corn exports. If the effects of ethanol production are large

enough to be measurable and identifiable, then this effect should certainly be taken into account in the assessment of corn-derived ethanol. Observation of the effect and validation of the model results is critical to validation of the greenhouse gas calculation for corn-derived and cane-derived ethanol. This section indicates that the GTAP model results cannot be validated, or have not yet been validated. Surely there is some aspect of the calculation that could be validated. For example, the changes in US forest and pasture land due to the federal RFS should be measurable.

p. IV-33, Table. IV-12. It should be possible to validate with data the projections of land use change resulting from cane-derived ethanol production in Brazil. The projections seem to be entirely model-derived, with no reference to studies of actual land use change in Brazil. The results should be validated with data. (PEERREVIEW3)

Response: We acknowledge these points – in general, validation of computable general equilibrium (CGE) model results is a difficult undertaking. CGE models report only the specific, incremental effects of the change or perturbation being modeled (e.g., increased demand for biofuels). Real world data on very specific, incremental effects such as these almost never exists. Data on exports, land conversion, caloric intake, trade volumes, etc. exist, but they consist of *aggregate* numbers: they reflect the net effect of many, often competing factors. The individual effect of any one factor usually cannot be teased out of them. The GTAP predicts that increased demand for ethanol will reduce corn and soybean exports, for example. The fact that aggregate corn and soybean exports actually rose over the period that was modeled is irrelevant. It just indicates that the factors tending to drive exports up (among them, rising meat consumption driving an increasing demand for livestock feed) tended to compensate for the downward pressure from the diversion of corn to ethanol production. Regardless of the actual aggregate trend in exports, it was lower than what it would have been in the absence of that diversion of the corn crop. Despite these difficulties, however, the GTAP, unlike most other CGE models, has been subjected to validation studies. The results of these studies have been used to improve and refine the model.

B-27. Comment: The lack of a time dimension in GTAP results in an awkward match with the question at hand. Corn yields have been increasing largely linearly for some time now in the United States, yet the model appears to use 2008 corn yields to determine land impacts of corn-derived ethanol. The projected steady increase in use of corn for ethanol in the US over the next few years suggests that land use change will be somewhat less than projected here.

p. IV-20. The GTAP model is not time dependent, whereas the land use change from biofuels is time-dependent. In particular, yields of corn and other feedstocks can be expected to increase in time. Although there is extensive discussion of this issue, particularly in Appendix C6, the expected increase in yield of corn beyond 2008 does not appear to be incorporated into the model.

p. IV-29. The results of the GTAP model are for a situation in which 13.25 billion gallons of increased ethanol production is produced in the year 2008. Yield will increase in subsequent years, requiring less land for a given amount of ethanol. If the increases in corn production occur after 2008, the land use impact will be less.

pp. IV-46. Increases in crop yield with time. The adjustments made to convert GTAP results from 2001 yields to 2006-08 yields; as described in Appendix C, do appear to be reasonable. However, the time profile of the land use change implied by the LCFS may warrant additional scaling of the GTAP results. In particular, if the increase in corn-derived ethanol is assumed to scale with the federal RFS, then the amount of corn used for ethanol will increase over time; if corn yields also increase over time then the land use impact of the corn-derived ethanol will decrease over time, although it will still be positive. However, if the amount of corn-derived ethanol used to fulfill the LCFS is constant, as suggested by the scenarios presented in appendix E, then the land use change would all be concentrated in the very near future (or even recent past). The time scenario for corn-derived ethanol production (how much in which year, and the total change in demand in each year) will affect the actual land use change and the actual greenhouse gas impacts. The land use change impact will occur in the year that land use changes, which will not necessarily be the same as the year of the increased use of corn-derived ethanol.

And, as discussed elsewhere for corn, sugarcane yields can be expected to continue to increase, suggesting that land use change impacts will decrease over time. (PEERREVIEW3)

Response: We agree that crop yields will likely increase in the future and that this will reduce the land use change impact of using crop-based feedstocks for biofuel production. However, our lifecycle assessments are designed to reflect current technology and agricultural practices and are not meant to predict future technologies or practices. As production technologies and agricultural practices evolve over time, the fuel lifecycle assessments will be periodically updated to reflect these changes. The two program reviews mandated by the LCFS will facilitate this.

B-28. Comment: The development of the land use change analysis for Brazilian sugarcane-derived ethanol appears to be less developed than the analysis of US corn-derived ethanol. The Brazilian analysis should be revised using up-to-date yield values, if they were not used in this analysis, and should reflect data on land use changes in Brazil.

Also, cane yield in Brazil has increased significantly over time. The cane yield used in the GTAP model is not mentioned, but if the 2001 baseline is used, then the modeled land use change would be larger than if the 2006-08 sugarcane yield were used. (PEERREVIEW3)

Response: As for the corn ethanol modeling, the sugarcane ethanol land use change impacts were adjusted to reflect the increase in sugarcane yields observed between the baseline year of 2001 and the 2006-2008 average. Furthermore, the land use change carbon intensity will periodically be adjusted to reflect future increases in crop yields as they occur. See also the response to Comment and B-27.

B-29. Comment: The LCFS staff report predicts that the LCFS will result in an overall savings in the State of California. The economic impacts of the LCFS will depend on future prices of petroleum and the future production costs of alternative fuels and vehicle technologies, which cannot be definitively predicted in advance. Nevertheless, the economic assessment appears reasonable, and the projection that the net economic impact will not be large and may even be slightly positive appears sound. (PEERREVIEW3)

Response: We acknowledge that the future production costs of alternative fuels and vehicle technologies may not be definitively predicted.

B-30. Comment: The LCFS staff report covers many of the environmental impacts well. An important set of environmental impacts that are not mentioned are the increased impacts of nitrogen, phosphorus, and other agricultural inputs from increased corn production. As mentioned in the report, the increase in corn production is not likely to take place in California. Nevertheless, the impacts may be significant at the national and international scale. Hypoxia in the Gulf of Mexico is linked to increased corn production. The use of nitrogen fertilizers and other agricultural inputs have a range of other environmental impacts that should be included in the environmental assessment. (PEERREVIEW3)

Response: We agree that the focus of the regulation on greenhouse gas emissions may result in some unanticipated environmental consequences as the production of alternative fuels accelerates. Because of this, the Board directed ARB staff to present a work plan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation. National and international impacts of expanded alternative fuel production on air, soil, and water quality will likely be considered in the process of developing these sustainability provisions.

B-31. Comment: The credit trading framework and details appear reasonable. Note that the credit trading provisions may help to reduce the actual land-use-change impacts of corn-derived and sugarcane-derived ethanol: When corn or sugar prices are high, regulated parties may choose to use less corn-derived or sugar-derived ethanol, which would help to moderate corn and sugar demand and reduce pressure to increase plantings of corn and sugarcane. (PEERREVIEW3)

Response: No response needed.

B-32. Comment: Table IV-I, page IV-3. This table appropriately separates the direct emissions from the land use effects, and appropriately shows fewer significant

figures for land use effects than for direct emissions. The direct emissions, however, should not be shown to four significant figures because the estimates are not that accurate; these results should be expressed to at most two significant figures. (PEERREVIEW3)

Response: We realize that, because of the uncertainty in calculations and complexity of complying with fractional values, carbon intensities with two significant digits would have advantages. However, in the compliance schedule the incremental carbon intensity reductions of gasoline and diesel fuels are so small, especially in the initial years of the LCFS, that four significant digits are necessary to quantify the reductions. In 2011, for example, the carbon intensity of diesel fuel reduces 0.25 percent dropping from 94.71 to 94.47 g/CO₂e/MJ, a change of only 0.236 g/CO₂e/MJ. With two significant digits, reductions would have to be nearly one percent to be quantifiable.

B-33. Comment: p. IV-17. Among the choices to meet demand for biofuel feedstock, one option not mentioned is to convert existing agricultural lands from non-food crops – such as cotton or tobacco, for example. (PEERREVIEW3)

Response: Land devoted to non-food crops such as cotton or tobacco is included in the GTAP data base and conversion of this land to biofuel feedstock production is allowed within the model. The ISOR should have been clearer in its description of how GTAP models land conversion.

B-34. Comment: p. IV-24. Of the three time accounting methods described, the first one is by far the most sensible. The Net Present Value calculation is not appropriate here. Net present value calculations are used for money because of the potential to invest money and receive a return overtime. That is not true for greenhouse gas emissions. The Fuel Warming Potential also is not appropriate; the greenhouse gases will remain in the atmosphere beyond the project time horizon, and presumably the policy interest is to reduce climate change impacts over a longer time horizon than this project time horizon. Presenting the net present value approach and the fuel warming approach gives the impression that these are valid approaches that could be used. I suggest that discussion of these approaches be dropped from the main body of this report, although retained in the Appendices. Development of these ideas in the peer-reviewed literature would provide a basis for inclusion in future ARB analyses.

p. IV-26. ARB staff appropriately uses the annualized method.

p. IV-47. Uncertainties associated with time-accounting. As mentioned before, it would be feasible, and add clarity to the model, to do more explicit time-dependent modeling. (PEERREVIEW3)

Response: As noted, the Board approved the annualized method and recognized that the NPV method as outlined in the ISOR is not appropriate for the accounting of time-varying GHG emissions (ISOR IV-26). The NPV method was included in the discussion

because it has been proposed for use in the literature and is currently being evaluated by the U.S. EPA for use in calculating land use change emissions for biofuels within the Renewable Fuel Standard. While the Board did not accept the Fuel Warming Potential (FWP) method, an article based on this method was recently published in a peer reviewed journal and therefore the method has received some scrutiny by the scientific community.⁴ The FWP method will also likely be a topic of discussion for the Expert Workgroup that is being convened at the Board's direction to further evaluate the estimation of land use change emissions. The FWP method will continue to be evaluated based on input from the scientific community and the Expert Workgroup on this matter.

B-35. Comment: p. IV-34. "As an initial estimate, we assumed a 75 percent coproduct credit for soy meal." ARB staff appropriately flags the uncertainty of this estimate. (PEERREVIEW3)

Response: No response needed.

B-36. Comment: p. IV-41-IV-42. This entire section expresses more certainty than warranted. Some judicious editing would prevent it from being misinterpreted. For example, in the bulleted list on p. IV-42, the word "about" should also be used in the last two bullets – these numbers are very uncertain. (PEERREVIEW3)

Response: Appendix C of the ISOR details the calculations forming the basis for this section and discusses the non-exact, illustrative nature of these values.

B-37. Comment: p. IV-48. The paragraph at the bottom of page IV-48 is solid. ARB should continue to refine its analysis and adjust the GHG emission values as the analysis develops, and data become available. (PEERREVIEW3)

Response: The Board directed staff to continue refining the analysis and adjust the GHG emission values as the analysis develops and data become available. Also see responses to Comments B-24 and B-27.

B-38. Comment: p. iii. The word "not" seems to be missing from lines 2. (PEERREVIEW3)

Response: This typographical error has been noted and will be included in the errata.

B-39. Comment: p. C-5. Energy Economy Ratios. In Brazil, development of flex-fuel vehicle technologies with higher compression ratios has provided an opportunity to increase the efficiency of vehicles using ethanol fuels somewhat. ARB may not want to incorporate this potential into its LCFS EERs, but this potential may warrant at least a one-sentence mention. (PEERREVIEW3)

⁴ Michael O'Hare and et al. (2009). Proper accounting for time increases crop-based biofuels' GHG deficit versus petroleum. UC Berkeley.

Response: The Board in Resolution 09-31 directed staff to continue evaluating the EERs and update as appropriate. At this time, not enough information exists to make this update.

B-40. Comment: p. C-27. A corn yield of 151.3 bushels per acre is mentioned here, but a corn yield of 160 bushels per acre is used in the derivation of the “110,000 acres of U.S. farmland” mentioned on p. IV-42 and derived on page C-41. The 160 bushels per acre may be taking into account future yield increases, as I have advocated above. The yield value assumptions, and the year to which each yield value is associated, should be clarified. (PEERREVIEW3)

Response: As stated on page C-41, the analysis presented on that page and pages IV-41 and 42 was meant to be illustrative and not exact and therefore used many approximate values. An average corn yield of 160 bushels per acre is one of these approximate values.

B-41. Comment: p. C-54. "Staff will revisit this issue and make updates to the co-product credit, as appropriate." ARB's commitment to revising the analysis is important and will improve the assessment; increased production of biofuels will provide more data with which to refine the analysis. (PEERREVIEW3)

Response: No response needed.

Response to Peer Review by Denise L. Mauzerall, Ph.D., Woodrow Wilson School of Public and International Affairs, Princeton University (JD)

B-42. Comment: The carbon intensity (CI) values play a key role in determining whether a regulated party has complied with the LCFS rule and hence will likely be carefully scrutinized by the regulated parties. Given the level of uncertainty in such calculations, it is not advisable to have so many significant figures for each entry. I believe that two significant figures would be sufficient. For example, diesel fuel would be more reasonably referred to as having a carbon intensity of 95 gCO₂e/MJ rather than 94.71gCO₂e/MJ. (PEERREVIEW4)

Response: See response to comment B-32.

B-43. Comment: In addition, it may be worth considering reducing the number of different subcategories for each type of fuel. I am concerned that establishing precise and accurate values for each fuel pathway (e.g. 11 different pathways for ethanol from corn) will be impossible and attempting to do so will create an undue burden on regulators and opportunities for the regulated community to argue that the specifics of their pathway are not accurate and need to be changed. However, some pathways are not presently included at all, for example, cellulosic ethanol and ethanol from waste products, which I assume will be added at a later time. (PEERREVIEW4)

Response: The LCFS uses multiple pathways for each fuel in order to provide both an accurate accounting of carbon intensity for each fuel and incentive for regulated parties to adopt production methods which result in lower emissions. Regulated parties must use the carbon intensity value that corresponds to the pathway that best represents their production process. Moreover, the carbon intensity value selected by the regulated party is subject to approval by the Executive Officer. If no pathway in the Lookup Table closely represents the fuel production process used by the Regulated Party, Method 2A or Method 2B can be used to generate a new, more representative pathway. Therefore, we believe that the inclusion of multiple pathways in the Lookup Table, the stipulation that the selection of a carbon intensity value is subject to Executive Officer approval, and the flexibility to generate new pathways using Methods 2A and 2B will result in an accurate representation of the carbon intensity for fuels subject to the LCFS and incentive to improve production methods.

Pathways for cellulosic ethanol and ethanol from waste products will be added to Lookup Table as these fuels enter the California fuel market.

B-44. Comment: When CI for diesel fuel and its substitutes is calculated is the radiative forcing (RF) effects of black carbon (BC) included? Although the calculation has significant uncertainty, assuming the RF of BC to be zero is incorrect and will affect calculations of the climate warming effects of combustion of diesel fuel in engines without good particulate filters and its substitutes. It is possible that fuels substituting for conventional diesel fuel will result in both higher and lower emissions of BC. The impacts of BC should be included in calculations of the gCO₂e for emissions from diesel fuel and its substitutes. This is likely particularly important for heavy-duty and off road applications of diesel engines as shown in Table ES~7. (PEERREVIEW4)

Response: Assembly Bill 32 does not include black carbon in the list of greenhouse compounds to be monitored and regulated. Also, the scoping plan does not include the effects of black carbon. Therefore, black carbon was not included in the LCFS lifecycle assessment modeling. We agree that the potential greenhouse effects of black carbon warrant further investigation and we will continue to evaluate the scientific literature on this topic.

B-45. Comment: Minimizing gCO₂e emitted per vehicle mile travelled rather than gCO₂e per MJ would be more effective at reducing total CO₂ emissions. The emphasis of the LCFS is on reducing the gCO₂e emitted per MJ of energy contained in the fuel. However, since the purpose of the standard is to contribute to reducing CO₂ emissions from California, I am concerned that the units used are essentially penalizing efficient vehicles with low CO₂ emissions per mile traveled. The inclusion of the proposed "energy economy ratio" (EER) values partially addresses this problem, however it requires that the correct EER value be applied for a suite of different technologies. The EER may vary in particular vehicles more than the EER values proposed in Table ES-7 imply. The standard

would be more effective if it focused on minimizing gCO₂e emitted per vehicle mile traveled rather than per MJ. The LCFS in its current form can only be certain to be effective at reducing total CO₂ emissions if it is coupled with programs to improve fuel efficiency. A "low carbon" fuel could be used in an inefficient vehicle and result in far higher total CO₂ emissions than a "high carbon" fuel would generate in a highly efficient vehicle. For example, consider two vehicles, an SUV which obtains 15 mpg and a hybrid vehicle which obtains 45 mpg. If each vehicle is driven 10,000 miles per year and both use standard gasoline the SUV will emit approximately 6.5 tons of CO₂ while the hybrid emits approximately 2.1 tons of CO₂. Even if the SUV used a fuel that had 30% less carbon, it would still emit approximately 4.6 tons of CO₂, more than twice the CO₂ of the hybrid. I recognize that given a static fleet composition, the LCFS is intended to reduce CO₂e emissions. However, it is imperative that reductions in CO₂e emissions per vehicle mile travelled be emphasized in the medium to long-term in order to encourage the development of vehicles which emit less CO₂e per mile travelled. (PEERREVIEW4)

Response: Executive Order S-01-07 states "a statewide goal be established to reduce the carbon intensity of California transportation fuels by at least 10 percent by 2020." Therefore, gCO₂e/MJ is the appropriate metric for the LCFS. Vehicle emissions of GHGs are regulated separately in California under ARB's AB 1493 regulation (section 1961.1, title 13, CCR). Together, the LCFS and AB 1493 regulations ensure significant reductions in greenhouse gas emissions per vehicle mile traveled.

B-46. Comment: Reevaluation of the gCO₂e/MJ emitted for biofuels is needed. The assumption in many analyses is that substituting biofuels for gasoline will reduce the emission of greenhouse gases because biofuels sequester carbon through the growth of the feedstock. This land use effect is included in the LCFS in a relatively uniform fashion with corn ethanol causing a 30gCO₂e/MJ and sugarcane leading to a 46 gCO₂e/MJ due to land use changes. These values may be fairly conservative, however. A recent analysis Searchinger et al. (2008) found that, relative to conventional gasoline, corn-based ethanol nearly doubles the emissions of greenhouse gases over 30 years and results in increased emissions of greenhouse gases for 167 years. They find biofuels from switchgrass, if grown on U.S. corn lands, increase emissions by 50%. In addition, Jacobson (2009) ranked cellulosic- and corn-E85 lowest overall of all fuel choices with respect to climate, air pollution, land use, wildlife damage, and chemical waste. Cellulosic-E85 ranked lower than corn-E85 overall, primarily due to its potentially larger land footprint based on new data and its higher upstream air pollution emissions than corn-E85. These results raise concerns about large biofuel mandates and highlight the value of using waste products. At present the LCFS does not include a carbon intensity value for fuels derived from waste products. Addition of a carbon intensity value for fuels derived from waste products is needed and is likely to be lower, and hence more attractive, than carbon intensity of ethanol derived from corn.

Despite the Searchinger et al. (2008) and Jacobson (2009) analyses, however, the CARB LCFS is assigning substantial reductions in total gCO₂e/MJ for ethanol derived from both corn and sugarcane. Table IV-20 indicates the CI the LCFS is proposing for emissions from gasoline to be approximately 96 gCO₂e/MJ. Table IV-20 indicates direct emissions from ethanol from corn are between 47-75 gCO₂e/MJ with a uniform contribution from "land use and other effects" of 30 gCO₂e/MJ resulting in total values from 77-105 gCO₂e/MJ; CI for ethanol from Brazilian sugarcane is approximately 73 gCO₂e/MJ with 27 gCO₂e/MJ from direct emissions and a contribution of 46g CO₂e/MJ from "land use and other effects". These values for biofuels appear to me to be optimistic and should be reevaluated in light of the new studies indicating lower reductions in GHG emissions derived from biofuel use as well as additional significant ecosystem, biodiversity and food supply harm resulting from growing food for fuel. (PEERREVIEW4)

Response: We acknowledge that there is uncertainty associated with land use change emissions. Although there may not yet be a true consensus on the appropriate method for estimating land use change, a number of highly regarded scientists have expressed their support for the approach taken by the Board. Acknowledging the uncertainty ranging around current LCFS land use change estimates, as well as the controversy those estimates have generated, the Board directed staff in Resolution 09-31 to convene an expert workgroup to assist the Board in refining and improving the land use effects analysis.

B-47. Comment: Encouraging penetration of extremely low carbon fuels is desirable. The emphasis on biofuels with 40% grown in California is undesirable. Biofuels do not appear, even by the LCFS proposed regulation, to be significantly better than gasoline in many cases. For example, the CI of corn ethanol grown in California ranges from 77-96% of the intensity of gasoline. California water can be better spent on other things than growing fuel. By contrast, the CI of electricity ranges from 35-41 gCO₂e/MJ and hence is far better than biofuels at reducing CO₂ emissions. In addition, compressed natural gas derived from landfill gas has a CI of 13 gCO₂e/MJ and can be used as an alternative to diesel. An additional emphasis on facilitating the penetration of these extremely low carbon fuels is desirable. (PEERREVIEW4)

Response: We acknowledge that some biofuels do not appear to be significantly better in carbon intensity than gasoline and possibly worse. The proposed regulation provides flexibility for regulated parties. They may supply a mix of different fuels above and below the standard that, on average, equal the required carbon intensity. They may also purchase credits by other fuel providers to offset any accumulated deficits from their own production. The LCFS does not limit the carbon intensity of individual types of fuels or necessarily promote biofuels over other alternative fuels such as compressed natural gas or electricity. In addition, the compliance schedule of the LCFS is back-loaded so smaller reductions in carbon intensity are required in the first five years than the last five years of the regulation. This schedule allows the usage of more

biofuels that may only be slightly better than gasoline in the early years of the regulation while advanced fuels that are lower in carbon are developed for the latter years of the regulation.

Response to Peer Review by Linsey C. Marr, Ph.D., College of Engineering, Virginia Tech

B-48. Comment: The rule is based on establishing carbon intensities for various transportation fuels and their substitutes. In purely scientific terms, it would be more sensible to measure lifecycle greenhouse gas emissions in grams of carbon dioxide equivalent (g CO₂e) per distance traveled in kilometers rather than per energy content of the fuel in megajoules (MJ) because the distance traveled is the more useful metric ultimately. Obviously, political and practical barriers hinder the more direct approach, so the LCFS establishes carbon intensities for each “fuel” and applies energy economy ratios to account for differences in the distance that can be traveled using various propulsion technologies. (PEERREVIEW1)

Response: See response to comment B-45.

B-49. Comment: The largest uncertainties in the estimation of carbon intensities are associated with the indirect effects. Relatively speaking, the magnitude of direct effects are much more certain. In keeping to this reviewer’s expertise, the comments presented here focus on direct effects, but readers should be aware that the uncertainties in this arena are smaller compared to those associated with land use change. (PEERREVIEW1)

Response: The Board acknowledged in Resolution 09-31 that the available methods for estimating indirect impacts (including land use change) are relatively new. As they continue to undergo development, the uncertainty associated with the impact estimates from these methods will decrease. In recognition of the relative infancy of the LUC analysis, the Board directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. The Board will consider the findings of the workgroup in its continuing efforts to improve the LUC assessment. In approving the LCFS, however, the Board found that current uncertainty levels are not sufficient to call into question the existence of significant indirect land use change impacts.

B-50. Comment: It is surprising that the fuel pathway for biodiesel is still under development and has not yet been completed. This is one non-petroleum fuel that is already widely used. I am not familiar with California’s biodiesel consumption rate, but in other parts of the country, substantial portions of the bus and equipment fleets are operated on biodiesel. According to the Department of Energy (http://www.afdc.energy.gov/afdc/progs/ind_state.php/CA/BD), there are dozens of biodiesel refueling stations in California, at least as many as there are hydrogen (http://www.afdc.energy.gov/afdc/progs/ind_state.php/CA/HY), for

which the fuel pathway has been completed. Biodiesel is a fuel currently in use whose carbon intensity should be included in this report. (PEERREVIEW1)

Response: Biodiesel from soybeans has both a direct and indirect effect contributing to its total carbon intensity. The CA-GREET model has used available data to calculate the direct emissions related to the farming, production and use of this fuel in a HD vehicle. The version of GTAP used to model the indirect effects for corn ethanol and sugarcane ethanol included only a composite oilseeds sector and did not account for the co-product credit resulting from production of soy meal during the soy oil extraction process. ARB has been updating the model to disaggregate soy from the oil seeds market and to accommodate the co-product credit. As discussed in Section I.A. of this FSOR, before this rulemaking is completed we plan to make the remaining soy biodiesel and soy renewable diesel carbon intensity values available to supplemental comment and to augment the regulation by including those values in the Lookup Table.

B-51. Comment: The development of energy economy ratios is straightforward with the current fleet, in which nearly all light-duty vehicles are gasoline powered, but a light-duty fleet with greater diesel presence, as was present in the past and is likely to be in the future, would require a modification to the approach. Eventually, propulsion technologies and vehicles will be produced without consideration of whether they are “replacing” gasoline- or diesel-fueled engines. How will energy economy ratios for such vehicles be calculated, i.e. to which fuel’s carbon intensity baseline will they be compared? For example, hydrogen producers whose product is used to fuel light-duty vehicles could argue that the hydrogen is replacing diesel fuel because there are some light-duty diesel-powered vehicles currently in existence, at least in other parts of the country if not California. (PEERREVIEW1)

Response: We have made a policy decision that the EER ratios for all light-duty vehicles and fuels used in light-duty vehicles will be computed using the fuel efficiency of gasoline vehicles as the baseline since the great majority of light-duty vehicles in the current fleet are gasoline vehicles. Therefore, for purposes of calculating credits, it is logical and reasonable to assume that any fuel used in light-duty vehicle is displacing gasoline. If the composition of the light-duty vehicle fleet changes significantly in the future and diesel vehicles achieve a greater presence, the staff will reevaluate this assumption and the need to make any changes.

B-52. Comment: Energy economy ratios certainly must be included to adjust for the different efficiencies of propulsion technologies in converting a certain amount of energy into linear motion. It would be instructive to report how variable the EER is across vehicle sizes. For example, what is the EER for a compact electric car versus a compact gasoline-powered car, and what is the EER for a large electric SUV versus a large gasoline-powered SUV? If the difference is large, multiple EERs may be needed for different vehicle classes. (PEERREVIEW1)

Response: We recognize that there may be differences in EERs with vehicle size. However, for the emerging advanced technology vehicles there is currently not enough data to make such a differentiation. ARB will review EER data as more vehicles are certified in the future.

B-53. Comment: The EER for plug-in hybrid electric vehicles (PHEVs) will require much more careful calculation once they are commercially available for testing. The value will depend very much on whether the vehicle is operating purely on electric power over its first ~30 miles or on its hybrid gasoline engine after this point. ARB will need to be able to make informed assumptions about the everyday use characteristics of PHEVs in order to determine an appropriate EER. How will updated EERs be handled? (PEERREVIEW1)

Response: We recognize that the EER will depend on whether the vehicle is in the purely EV mode or the hybrid mode. But the regulation only gives credit for the amount of grid electricity used by PHEVs. So the relevant question for us is the amount of gasoline that is saved by the individual's decision to drive a PHEV in the electric model instead of a gasoline vehicle. That is, for each grid kW-hr the PHEV uses, how much gasoline is saved because the vehicle is using electricity instead of gasoline? The EER in the purely electric mode gives us this. So EERs for PHEVs operating in a blended mode are not really relevant to us. Also, we will be updating EERs as new data becomes available.

B-54. Comment: Finally, with regard to EERs, a discussion of the importance of idling by heavy-duty trucks is warranted because EERs are not valid during idling. Does idling comprise a sufficiently small fraction of total diesel consumption that it can be neglected? Are idle reduction programs in place in California? What are the carbon intensities for "shore" electric power replacing diesel consumption in this case? (PEERREVIEW1)

Response: Idling comprises only a small fraction of total diesel consumption, and that was true even before ARB put the idling limit regulation (section 2485, title 13, CCR) in place. This regulation limits heavy duty vehicle idling to 5 minutes. It appears unlikely that the bio-refineries provide "shoreside" electric power for the trucks. Unloading biomass and loading fuel tanks is expected to be a fairly quick process, which means there would not be a significant need for "shoreside" electric power to prevent idling emissions. If shoreside power were provided, however, the appropriate carbon intensity is expected to be that of California marginal electricity.

B-55. Comment: (p. ES-15) Table ES-5 indicates that two pathways for electricity generation have been completed for average and marginal electricity used in the state. Given the growth in renewables, are sources of electricity expected to change enough over the next 10 years that the carbon intensity for either pathway will be different in 2020? (PEERREVIEW1)

Response: Yes. California generates between 66 and 75 percent of its electricity in-state and imports the needed balance from generators within the Western Electric Coordinating Council area. While imported electricity accounts for approximately 25 to 30 percent of total electricity consumed in-state, it contributes more than half of the GHG emissions associated with California's electricity consumption because California's imports are dominated by coal-generated electricity.

California's Emission Performance Standard (EPS) will help reduce emissions related to out-of-state coal generation. The EPS precludes California's electric utilities from making investments in, or entering long-term purchase contracts for, baseload electricity generation exceeding 1100 pounds of CO₂e per megawatt-hour. California's utilities have contracts and/or ownership arrangements with five out-of-state coal power plants that will change or expire by 2020. The impact of these changes is that, by 2020, California will reduce coal-based generation from imports by approximately 10,000 GWh, responsible for about 9.7 MMTCO₂e.

Assuming that this electricity is replaced with electricity generated from combined cycle natural gas plants, the EPS will reduce California's emissions from imported electricity by almost five million metric tons of CO₂e emissions annually. Larger reductions are possible if renewable energy is used to replace coal power.

ARB's AB 32 Scoping Plan recommends that electricity service providers meet 33% of their electricity sales with qualifying renewable power, such as wind, solar, biomass, geothermal, and small-hydropower resources. The Scoping Plan estimates that the 33% renewable energy mix will reduce CO₂ emissions by 21 MMT in 2020. Given the size of this reduction, added to the reductions gained by expiring coal generation contracts, the carbon intensity for both California's marginal and average electricity mix pathways is expected to decrease significantly.

B-56. Comment: (p. ES-19) Table ES-7 lists the energy economy ratio for electricity substituting for diesel as 3.0, but everywhere else in the report, this value is given as 2.7. (PEERREVIEW1)

Response: The correct value for the energy economy ratio for electricity substituting for diesel in Table ES-7 should be 2.7 rather than 3.0.

B-57. Comment: (p. ES-36) Both the Pavley regulation and the LCFS will achieve GHG reductions from vehicles. Further clarification is needed as to the interaction between the two rules, i.e. how to avoid double-counting emissions reductions. (PEERREVIEW1)

Response: We have made adjustments in the ISOR analyses to avoid double counting the greenhouse gas benefits of the LCFS and the motor vehicle regulations. We also plan to monitor closely the vehicle and fuel mix and compliance with both the motor vehicle regulations (Pavley, ZEV regulation, and the low emission vehicle regulation)

and with the LCFS, and make any necessary changes to the regulations to ensure there is no double crediting and thus to preserve the emissions benefits of the regulations.

B-58. Comment: (p. IV-1) “In general, a land use change occurs when farmland devoted to food and feed production is diverted into biofuel crop production causing supplies of the displaced food and feed crops to be reduced.” Is it also the case that land formerly dedicated to non-agricultural use might be converted to biofuel crop production directly? (PEERREVIEW1)

Response: Yes, the GTAP model includes the direct conversion of non-agricultural land into land for the production of biofuel crops.

B-59. Comment: (p. IV-10) Figure IV-1 would be more accurate if it showed each component of the direct effects summing to the direct effects. In its current form, the figure suggests that total direct effects are added to its components, effectively double-counting these. (PEERREVIEW1)

Response: We concur with the reviewer. The total direct effects would be the sum of the feedstock recovery, processing, processing co-products benefits, transportation, and combustion – that might be more clearly indicated with a bracket or shaded area around those sources. The figure would be clearer if there were a separate co-products box above land use change.

B-60. Comment: (p. IV-16) Regarding the discussion of indirect effects resulting from intermediate market mechanisms, e.g. vehicle production, these are usually minor compared to direct emissions associated with vehicle operation. MacLean and Lave (2003, Environmental Science and Technology) showed that the majority of energy and GHG emissions are associated with use of the vehicle rather than production of it, so it is correct to focus on emissions from driving. (PEERREVIEW1)

Response: We agree that the combustion emissions from the use of a conventionally-fueled vehicle over its life would be larger than the emissions from the production of the vehicle, and that it is appropriate to focus on the tailpipe emissions.

B-61. Comment: (p. C-57) “Due to lack of available data for Venezuelan crude, extraction and processing emissions were assumed to be similar to heavy oil recovery and processing in GREET. The GHG emissions associated with heavy oil recovery were based on the GREET calculations for oil sands assuming that the fuel source was bitumen.” Insufficient information is provided to justify this assumption. Is Venezuelan crude recovery known to be closer to heavy oil recovery than primary recovery? What recovery method is assumed for other countries? If it is the same 98% recovery efficiency assumed for Alaskan crude, why are the Alaskan and Other Imported carbon intensities different in Table C12-6? Do they have different heating values? (PEERREVIEW1)

Response: Yes, Venezuelan heavy crude has a low API gravity (around 15 or lower) and for this analysis, it was therefore considered (energy inputs) to be similar to heavy oil recovery. For other imported crudes and that from Alaska, primary recovery method was assumed and the CA-GREET model utilizes a 98% recovery efficiency for primary recovery methods. This is based on the API of these crudes. Though the same recovery efficiency (98%) is used for both Alaska and imported crude (non-Venezuelan), there are other factors such as flaring, associated gas venting, etc. that are considered by the model. These values are different for U.S. and overseas sources and leads to differences in recovery carbon intensities. As for heating values, it is not part of the calculation process.

B-62. Comment: (p. C-59) “These emissions are then included in the statewide overall fuel mix using the 40% cogeneration, 60% OTSG weighting described above.” The 40%/60% weighting described on the previous page is described as being based on the steam-oil-ratio and not whether cogeneration is used. Clarification is needed. (PEERREVIEW1)

Response: One 40% to 60% ratio refers to the split of fields using a Steam-Oil Ratio of 3.08 to those using a Steam-Oil ratio of 5.13. This was based on data from the Department of Oil, Gas and Geothermal Resources (DOGGR) in CA and recognizing the fact that 3 fields constituted more than 80% of CA heavy crude production. The other 40% to 60% ratio is the breakdown of the OTSG and the Cogeneration sites, also from DOGGR data.

B-63. Comment: The most contentious component of the rule is likely to be the inclusion of indirect effects of biofuels. Although land use change is not my area of expertise, I concur that such factors must be taken into account because an important recent study showed that land use change associated with the production of corn-based ethanol doubles greenhouse gas emissions over 30 years and increases those from switchgrass-based ethanol by 50% (Searchinger et al., 2008). Ignoring land use change would likely be counterproductive to the goals of the LCFS. As the ISOR notes on p. IV-45, some stakeholders argue for land use change carbon intensities near 0 gCO₂e/MJ, while others propose using values of 100 gCO₂e/MJ or higher. Obviously, large uncertainties still exist in the estimation of these values, so the rule should have some provision for incorporating improved estimates as they become available. Beyond this general observation, I am not qualified to review the scientific basis of the land use modeling. (PEERREVIEW1)

Response: A significant amount of work has been done since the Searchinger article was published, and staff has incorporated input from many stakeholders in the analyses for the LCFS. Resolution 09-31 includes the following: “BE IT FURTHER RESOLVED that the Board directs the Executive Officer to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address

issues identified. This workgroup should evaluate key factors that might impact the land use values for biofuels including agricultural yield improvements, co-product credits, land emission factors, food price elasticity, and other relevant factors. The Executive Officer shall coordinate this effort with similar efforts by the U.S. Environmental Protection Agency (U.S. EPA), European Union, and other agencies pursuing a low carbon fuel standard.” See also FSOR responses to comments related to Land Use Change.

B-64. Comment: Appendices F2, F4, and F5 carefully consider criteria pollutant emissions associated with fossil fuel refineries projected to the year 2020. Full lifecycle emissions are considered for new ethanol and biodiesel capacity at a detailed level. For instance, emissions are calculated from truck trips for distribution of the feedstock and fuel, and emissions with rail transport of imported fuel are also estimated. For biofuel production facilities, emissions estimates go into a detailed level, even including emissions from backup electrical generators. The assessment of criteria pollutant emissions is based on sound scientific knowledge, methods, and practices, although a few details can be improved, as listed in the section below. (PEERREVIEW1)

Response: No response needed. Responses to the comments below address the issues related to biofuel production emission estimates that the commenter has identified as needing clarification.

B-65. Comment: The health risk assessment uses an inconsistent approach to pollutant dispersion for carcinogenic versus non-carcinogenic effects and seems unfairly focused on the negative effects associated with biorefinery emissions while overlooking positive effects associated with reductions in emissions from a fleet containing more advanced vehicles. The health risk assessment for emissions associated with biorefineries indicates that they will be associated with approximately 24 premature deaths; 8 hospital admissions; and 367 cases of asthma, acute bronchitis and other lower respiratory symptoms. Because emissions from the facilities themselves are expected to be offset, the main source of net emissions is diesel truck traffic to and from the facilities. It would be fairer to put these numbers in the context of the overall effect of the LCFS, rather than to present them in isolation. Why does the health impacts section not include mortality and morbidity avoided due to reductions in tailpipe emissions? As a result of the LCFS-inspired introduction of advanced vehicles, tailpipe emissions from the vehicle fleet will be lower, and the reductions in mortality and morbidity are likely to outweigh the effect presented in the detailed risk assessment about biorefineries. (PEERREVIEW1)

Response: The discussions of LCFS health impacts have been edited since the March 2009 Initial Statement of Reasons was published to include the potential emissions benefits of advanced vehicles which could be used to comply with the LCFS.

“Health Impacts Associated with Emissions from Potential Biorefineries (edited October 2009)” is attached.⁵

B-66. Comment: (p. VII-18) “Staff estimates a maximum increase of 84 ton/year VOC evaporative emissions from refueling results in switching to scenario 2 volumes of E10 and E85 in 2020, as opposed to not switching from an energy equivalent volume of CaRFG3 fuel (E10). The other scenarios offer somewhat smaller increases. Emission standards for vehicles which use E85 are the same as for vehicles which use gasoline. Therefore, staff does not expect to see a significant difference in the emissions.” This statement overlooks evaporative emissions. Increased hot soak, running loss, and diurnal emissions are also expected with a higher volatility fuel such as E85, but the report does not address these. Emissions standards apply to tailpipe emissions only and not evaporative emissions, so an argument based on standards only is incomplete. Knowing the vapor pressure of E85 versus RFG and evaporative losses from gasoline-powered vehicles should enable the calculation of engineering-based estimates of such losses with E85. (PEERREVIEW1)

Response: The referenced sentence should read, “Exhaust and evaporative emissions standards for vehicles which use E85 are the same as for vehicles which use gasoline.” The commenter states that increased evaporative emissions are expected with a higher volatility fuel, a true statement, but that does not apply here. Neat ethanol has a vapor pressure, approximately 2.3 pounds per square inch (psi), much lower than summer CaRFG which is typically about 6.9 psi. Thus E85 blended from a gasoline of a given vapor pressure will have a lower vapor pressure than the same gasoline alone. Data submitted to ARB by E85 suppliers in California indicate that vapor pressures in summer are typically 4-5 psi.

Gasoline-oxygenate blends exhibit volatility characteristics unlike those of gasoline, however. Blending alcohol into gasoline forms a nonideal solution that does not follow linear blending relationships. Rather than lowering vapor pressure, ethanol causes an increase of about 1 psi in a 9 psi RVP gasoline (5-20 vol. percent ethanol)¹. Furthermore, ethanol vapors may exist in concentrations disproportionate to the alcohol concentration in the blend. Gasolines with lower vapor pressures incur larger increases in vapor pressures than gasolines with higher vapor pressures. Commingling studies are available which may indicate whether this is also true with E85 but additional time is required for their review.

B-67. Comment: (p. VII-19) “Emissions of formaldehyde (HCHO) were also greater on E85 than on gasoline, showing a much larger difference, although there was only one pair of test values (DaimlerChrysler).” Larger emissions of formaldehyde could be important for air quality because of its role as an initiation species in photochemistry. Additionally, formaldehyde is an air toxic. This topic merits

⁵ The attachment “Health Impacts Associated with Emissions from Potential Biorefineries (edited October 2009)” is being included here in response to comments for clarification and to included updated emission factors. However, the analysis is the same as that the Board used to approve the regulation.

additional consideration. Recent studies in the literature also conclude that formaldehyde emissions will be higher with E85 (Graham et al., 2008; Yanowitz et al., 2009). (PEERREVIEW1)

Response: A review of California certification data for 2008 model year flexible fuel vehicles shows that GM and Daimler Chrysler tend to have higher NMOG emissions on E85 than gasoline, while Ford tends to have less. CO is the opposite: GM and DaimlerChrysler tend to have lower emissions on E85 than gasoline, while Ford shows no difference. GM also tends to have higher NOx emissions on E85 than gasoline, while Ford and Daimler Chrysler tend to have less. As noted by the commenter and in the ISOR, emissions of formaldehyde were also greater on E85 than on gasoline.

B-68. Comment: (VII-19) “This is because staff is currently conducting an extensive test program for biodiesel and renewable diesel and will follow that effort with a rulemaking to establish specifications to ensure there is no increase in NOx.” This statement assumes that NOx emissions can be controlled through fuel specifications. Because much of NOx originates from thermal formation and not the fuel itself, the approach may not work; it may not be possible to control NOx emissions through specifications on biodiesel. In this case, the assumption that biodiesel will cause no increase in NOx emissions is unjustified, when studies in the literature suggest that NOx emissions increase with the use of biodiesel versus petroleum-based diesel. (PEERREVIEW1)

Response: We acknowledge the reviewer’s comment that NOx is generally higher with biodiesel and biodiesel blends than diesel. Also, the NOx difference typically increases as the blend level increases, with pure biodiesel (B100) generally having highest NOx difference. Although NOx is caused by thermal formation, a number of studies show that fuel specifications can affect NOx emissions. The reviewer notes that fuel specifications alone cannot make biodiesel NOx neutral, and this may be the case for higher blends or B100. However, staff believes that lower blends of biodiesel can be mitigated by adjustments to fuel specifications. Therefore, staff believes that controlling fuel specifications can, to some extent, mitigate increases in NOx associated with biodiesel fuels, at least at lower blend levels. Also, the use of additives and lower NOx biodiesel may extend the blend level so that NOx can be mitigated.

Other potential strategies may include blending biodiesel feedstocks with other low NOx feedstocks, such as renewable diesel or gas-to-liquids diesel substitutes, to counteract the NOx increase due to biodiesel. The preliminary results from ARB’s ongoing biodiesel emissions study suggest that NOx emissions may be mitigated for biodiesel blends (up to B20) that are made from soy, which is a feedstock that has been shown to be on the high end for NOx emissions.

B-69. Comment: (p. VII-20) “Clearly the major impact is associated with the additional truck trips.” This sentence refers to Table VII-13, which summarizes changes in criteria pollutant emissions stemming from the LCFS and shows that the major increase in emissions is due to additional truck trips, but the net result is still a

decrease in criteria pollutant emissions. In terms of magnitude, the major impact comes from ZEVs, not additional truck trips. (PEERREVIEW1)

Response: We acknowledge that the magnitude of the reduction in criteria pollutant emissions from ZEVs outweighs the truck trip emissions, if total criteria pollutant emissions are aggregated on a statewide basis. However, as discussed in the ISOR, the localized impacts of diesel PM from trucks and biorefinery facility emission are of concern and need to be considered.

B-70. Comment: (p. VII-22) "...it is not practical to expect the air quality model to reasonably predict the impact on ozone air quality." This statement is correct, so it would be impractical to expect the section on environmental and multimedia impacts to predict changes in ozone in a meaningful way. (PEERREVIEW1)

Response: The commenter concurs with statements in the ISOR that due to the low magnitude of emissions associated with the LCFS, the air quality model cannot predict changes to ozone concentration that may result from the LCFS. Hence, there is no additional analysis of LCFS impacts on ozone concentrations in the ISOR section on environmental and multimedia impacts.

B-71. Comment: (p. VII-33) While the LCFS does not appear to trigger the multimedia evaluation requirement, the regulation will change the mixture of fuels being used in the state, and the much larger amounts of ethanol and biodiesel being used may have multimedia effects, some of which have been addressed in this chapter. In keeping with the spirit of the regulation, the report appears to address multimedia evaluation requirement properly. (PEERREVIEW1)

Response: No response needed.

B-72. Comment: (p. F-6) "Using the baseline information presented above, the 'Tank-to-Wheel' emissions with the LCFS can be determined. This is done by assuming that there is a 10% reduction in the 'tank-to-wheel' carbon intensity factor for each year." On what basis is the assumption of a 10% reduction in the tank-to-wheel carbon intensity factor for each year made? A 10% reduction per year sounds like a lot, especially given that the LCFS calls for a 10% reduction in carbon intensity over a full decade, at least for the full fuel cycle. The values appearing in Table F-1 do not correspond to a 10% reduction per year. This section needs to be clarified, and the 10% reduction per year in "tank-to-wheel" carbon intensity more thoroughly justified. (PEERREVIEW1)

Response: The statement "This is done by assuming there is a 10% reduction in the 'tank-to-wheel' carbon intensity for each year" is incorrect. This sentence should read, "This is done by assuming there is a 10% reduction in the 'tank-to-wheels' carbon intensity in 2020." Additionally, Table F1-1 represents the baseline emissions and does not reflect the affects of the LCFS rulemaking. Gasoline energy requirements go down due to the ZEV mandate and Pavley 1 and 2. Diesel energy requirements go up due to

an increase in fleet size. Table F1-3 provides the energy requirements and GHG emissions if the LCFS were implemented. The energy requirements for the fuels remains the same through 2020, but the amount of GHG emissions are reduced by 10% in 2020.

B-73. Comment: (p. F-35) Why is the Western Biomass Energy plant used as the only basis for projection of future emissions from cellulosic ethanol facilities? Table F5-2 lists two other facilities in Georgia and Louisiana that also cellulosic ethanol, and the Range Fuels Biofuels plant's NOx and PM10 emissions per volume of fuel produced are much higher. Is the gasification catalytic process used by this plant, versus the weak acid hydrolysis process used by the other two plants, not expected to be used in the future? (PEERREVIEW1)

Response: Western Biomass Energy was chosen as the scale-up plant for the environmental analyses for two reasons. First, the economics analysis focused on a weak acid hydrolysis plant and this was chosen for consistency. Secondly, of the two facilities, Western Biomass Energy had the most detailed permit, making possible to apply California Best Available Control Technology (BACT) to appropriate equipment within the facility.

B-74. Comment: (p. F-42) "The staff has developed five hypothetical compliance scenarios for compliance with the gasoline LCFS. For each of these five scenarios the staff has estimated the amounts of low-carbon intensity corn ethanol, cellulosic ethanol, sugarcane ethanol, and advanced renewable blendstocks that would be needed to meet the required 10 percent reduction in greenhouse gas emissions." The introduction of these five scenarios is confusing because previously, the report discussed four compliance scenarios (Appendix E). How are the two sets of compliance scenarios related? If they are not, they should be aligned with the previously presented compliance scenarios. (PEERREVIEW1)

Response: There are four core scenarios plus some supplemental scenarios. The referenced sentences should read, "The staff has developed four hypothetical compliance scenarios for compliance with the gasoline LCFS (p. VI-11), plus the supplemental 'No Indirect Land-Use Change Scenario' presented in section VI.C.2 (p. VI-18). For each of these four core and the supplemental No Indirect Land-Use Change scenarios ...". Scenario 5 in Table F6-3 would be better identified as the supplemental No Indirect Land-Use Change Scenario.

B-75. Comment: (p. F-43) "Regulations for vehicles which use E85 are the same as for vehicles which use gasoline." This statement contradicts the values shown in Table F6-4 on the following page, which lists the NMOG standards as 0.089 g/mi for E85 and 0.095 g/mi for gasoline. For the other pollutants, the standards agree. (PEERREVIEW1)

Response: There is a less stringent NMOG standard for flexible fuel vehicles operating on gasoline rather than on E85. This is because for flexible fuel vehicles, the engine calibrations were optimized for E85, not gasoline, making it difficult to meet the NMOG standard on gasoline during cold starts.

B-76. Comment: (p. F-45) The review of certification data for FFVs contains statements with contradictory justification, or at least the results are hastily presented without statistical validation. The first point on the page, “Certification values in grams/mile for non-methane organic gases (NMOG) on E85 are mostly greater than on gasoline, more so at 50,000 miles than at useful life,” claims that NMOG certification values are mostly greater on E85 (0.049 g/mi) than on gasoline (0.044 g/mi), differing by 11%. The third point on the page, “Certification values in grams/mile for oxides of nitrogen (NOx) on E85 are about the same as on gasoline, both at 50,000 miles and useful life,” states that NOx certification values are about the same on E85 (0.03 g/mi) and gasoline (0.04 g/mi), but the difference between these two values is larger, 29%, than for NMOGs (11%). Because the formaldehyde comparison is based on a single pair of values, the fourth point, “Certification values in grams/mile for formaldehyde on E85 are greater than on gasoline, both at 50,000 miles and useful life (note however there was only one pair of values for each),” relies on a weak basis. (PEERREVIEW1)

Response: See response to Comment B-67, which provides an updated analysis. The results indicate that emissions of NOx decrease for E85 vehicles, compared to gasoline vehicles.

B-77. Comment: (p. F-46) “ARB staff is continuing to examine California certification data of 2008 and 2009 flexible fuel vehicles to see if there are significant differences in emissions between gasoline and E85.” Such a review is critical to assessing the criteria pollutants’ emissions impacts related to the LCFS. The review should analyze the data in much greater depth than presented in this report. (PEERREVIEW1)

Response: See response to Comment B-67.

B-78. Comment: (p. F-51) The mention of five light-duty vehicle deployment scenarios that are collapsed into three is confusing. Unless the five scenarios correspond to scenarios used elsewhere in the report, these could be presented more clearly as simply three scenarios. Table F8-1 would be more easily interpreted if values were presented in thousands of vehicles rather than millions since the numbers are so small in all but Scenario 4’s PHEVs in 2020. (PEERREVIEW1)

Response: There are four core scenarios plus some supplemental scenarios. The referenced sentences should read, “The staff has developed four hypothetical compliance scenarios for compliance with the gasoline LCFS (p. VI-11), plus the supplemental ‘No Indirect Land-Use Change Scenario’ presented in section VI.C.2 (p.

VI-18). For each of these four core and the supplemental No Indirect Land-Use Change scenarios ...". Scenario 5 in Table F8-1 would be better identified as the supplemental No Indirect Land-Use Change Scenario.

B-79. Comment: (p. F-52) Table F8-2's footnote claims that emission values are rounded to two significant digits, but entries smaller than 10 tons/year show only one significant figure. Table F8-3 showing emissions reductions in tons per day is redundant because the previous table, F8-2, shows the same information in tons per year. (PEERREVIEW1)

Response: Table F8-2 should be revised to include 2 significant digits for all numbers.

B-80. Comment: (p. F-61) The health risk assessment for diesel emissions associated with truck deliveries to biorefineries uses up-to-date modeling techniques with appropriately conservative assumptions. Please clarify whether this activity is expected to have the greatest negative health impact of all changes in emissions associated with the LCFS. For example, new biorefineries will emit criteria and toxic air contaminants from their stacks. Even though such emissions are expected to be offset, they will have local impacts. Are the risks from these emissions expected to be less than for the diesel trucks servicing the facilities? Why isn't a health risk assessment performed for changes in criteria pollutant and air toxic contaminant emissions from tailpipes? The health risk reduction from such an analysis is likely to far outweigh the case study presented in this section. (PEERREVIEW1)

Response: In 1998, ARB identified particulate matter from diesel exhaust (diesel PM) as a toxic air contaminant based on its potential to cause cancer and other adverse health problems. Diesel PM typically accounts for about 70 percent of the State's estimated potential ambient air toxic cancer risks. This estimate is based on data from ARB's ambient monitoring network in 2000. These findings are consistent with that of the study conducted by South Coast Air Quality Management District: Multiple Air Toxics Exposure Study (MATES-II) in the South Coast Air Basin in 2000. According to The Air Toxics Hot Spots Program Risk Assessment Guidelines issued by Office of Environmental Health Hazard Assessments, the criteria pollutants either are not considered as carcinogens, or do not have an assigned cancer potency factors. The non-diesel PM air toxic contaminants have much less estimated potential ambient air toxic cancer risks than diesel PM. ARB 17 Railyard Health Risk Assessment Studies indicated that the cancer potency weighted emissions of top four non-diesel PM carcinogen compounds are about 11 percent of that of diesel PM. Therefore, the health impacts in this study primarily focus on the risks from the diesel PM emissions.

B-81. Comment: (p. F-63) "Staff also assumes each truck to be idling at the loading and unloading area located in the center of the facility for five minutes." Five minutes of idling sounds optimistically low in the analysis of diesel truck emissions from biorefineries. (PEERREVIEW1)

Response: The California Heavy-Duty Vehicle Idling Emission Reduction Program (section 2485, title 13, CCR) requires 2008 and newer model year heavy-duty diesel engines to be equipped with a non-programmable engine shutdown system that automatically shuts down the engine after five minutes of idling or optionally meet a stringent oxides of nitrogen idling emission standard. The in-use truck requirements require operators of both in-state and out-of-state registered sleeper berth equipped trucks to manually shut down their engine when idling more than five minutes at any location within California beginning in 2008.

B-82. Comment: (p. F-73) Unlike the health risk assessment for carcinogenic effects, which undertook dispersion modeling around hypothetical biorefineries, the non-cancer health risk assessment assumes emissions to be spread across the air basin. Inconsistent approaches are taken to estimating health risk for cancer versus non-cancer effects. Please explain the reasoning behind the different approaches. Appendix F11 provides little detail on the emissions being considered, so the reader is assuming that like in Appendix F10, they are the emissions associated with increased diesel truck traffic to and from biorefineries. (PEERREVIEW1)

Response: Two different approaches were used to assess the health impacts of exposure to particulate matter, one for cancer and one for non-cancer effects, because these are the only methodologies that are available to quantify these health endpoints. The two assessments differ in their inputs and outputs as described below: The cancer risk assessment is calculated using an inhalation unit risk, which describes the cancer risk per $\mu\text{g}/\text{m}^3$, and a hypothetical scenario that includes the pollutant concentration, breathing rate, body weight, exposure duration and averaging time. The result of the cancer risk assessment is the lifetime probability of excess cancer risk in a hypothetically exposed population. The health impacts analysis, which includes premature mortality, hospitalizations and work loss days, is calculated using concentration response (C-R) factors. The C-R factors are derived from epidemiological studies that relate the concentration of fine PM with adverse health outcomes. Health impacts are calculated using the C-R factor, the concentration of diesel PM throughout the state at the census tract level, population demographics at the census tract level, and baseline health incidence levels. The result of this assessment is an estimate of the number of cases of health effects for the actual population of the state.

B-83. Comment: (p. F-76) “Biorefinery emissions were not included in the health impact calculation because increased local emissions from biorefineries are expected be offset by decreased emissions within the air basin.” This assumption seems hasty because it is unlikely that local emissions from biorefineries exactly offset decreased emissions within the air basin. Furthermore, local emissions from biorefineries affect mainly the air basins in which they are located, while decreased emissions (from tailpipes I assume) are statewide. (PEERREVIEW1)

Response: An analysis of health impacts of the Low Carbon Fuel Standard was included in the March 2009 document entitled “The Proposed Regulation to Implement the Low Carbon Fuel Standard, ISOR: Initial Statement of Reasons”. While the conclusions of the analysis have not changed, minor adjustments to the impacts have been made using updated emissions factors. The potential health impacts have been reduced slightly as a result of the updated factors. In addition, in response to public comments, this update includes expanded analysis to put the estimated health impacts in perspective as they relate to the benefits of other components of the LCFS program. Finally, the relationship between health impacts due to the LCFS program and impacts due to the federal RFS program are also examined for potential overlap. The references used in the update are identical to those cited in the ISOR and submitted for public record.

The health impacts analysis published in March 2009 calculated seven non-cancer health impacts that could result from emissions from new biorefinery operation in California and emissions from the transport of imported fuel (ethanol and biodiesel) into the state. The analysis has been edited to clarify the fact that these are impacts that, if considered without regard to benefits of the LCFS, would increase the number of premature deaths, hospital admissions due to respiratory or cardiovascular causes, cases of asthma-related and other lower respiratory symptoms, cases of acute bronchitis, and number of work loss and minor restricted activity days.

The analysis also now incorporates emission factors from an updated emissions model (EMFAC 2007v2.3) to calculate emissions from biorefinery truck transportation and from transporting imported fuel. The slightly revised emissions calculations have lowered the previously published estimates of health impacts.

ARB staff received comments and questions about the relationship between the health impacts due to biorefinery transportation and imported fuel transport calculated in the ISOR and the health *benefits* of other components of the LCFS program. In response to these comments, staff has included the health benefits that could result from the increased use of advanced vehicles in California.

Finally, the analysis examines the impact of the requirements of the federal RFS2 program and what portion of the health impacts attributed to the LCFS would also occur under the federal requirements. Staff has concluded that under the majority of scenarios examined, emissions attributed to the LCFS would occur under the federal program also if the LCFS did not exist. As shown in Table F11-4, estimates of the volume of ethanol and diesel fuel that will be produced in California and imported into the state due to the federal program are in most cases greater than the volume of these fuels included in the LCFS scenarios. Therefore, health impacts that could occur as a result of the LCFS program could potentially also occur in the absence of the LCFS program. The analysis recognizes and clarifies this potential programmatic overlap.

Table 1 below compares the number of potential health impacts that could occur as a result of biorefinery transport presented in the ISOR to the number of potential health

impacts using updated emissions factors. Also shown are the potential health impact benefits of the use of 1,000,000 advanced vehicles in California.

Table 1: Summary of the Potential Health Impacts and Benefits Associated with Emissions Related to Possible Biorefineries and Advanced Vehicles in Year 2020

Endpoint	Additional Potential Cases due to Biorefinery Transport Emissions (As reported in ISOR)	Additional Potential Cases due to Biorefinery Transport Emissions (Update from ISOR)	Fewer Potential Cases as a result of Advanced Vehicle Benefits (1)
Premature Death	+24	+20	-130
Hospital Admissions (Respiratory & Cardiovascular)	+8	+7	-45
Asthma & Lower Respiratory Symptoms	+340	+290	-2190
Acute Bronchitis	+27	+24	-184
Work Loss Days	+2,200	+1,900	-13,900
Minor Restricted activity days	+13,000	+11,000	-81,000

(1) Based on 1 million advanced vehicles (benefit difference between 2 million market-driven advanced technology vehicles and 1 million improved ZEV regulation vehicles).

Please see attachment “Appendix F11, Health Impacts Associated with Emissions from Potential Biorefineries, (edited October 2009)”. This reflects Appendix F11 to the ISOR, with updated corrections and revisions.

B-84. Comment: (p. F-83) “Thus the proposed LCFS candidate fluid fuel production schemes should not create a water use problem if sited near large coastal WWTP and utilize ocean discharge water. Sites located inland may face difficulty finding water supplies.” This is a good recommendation, but on p. VII-9, the document states, “Production facilities would be located in close proximity to local feedstocks.” For biofuels, feedstocks, i.e. crops, are likely to be grown in the Central Valley, not near the ocean. A single recommendation for siting of liquid fuels, considering both water quality and consumption and transport of feedstocks, would be useful. (PEERREVIEW1)

Response: Choosing where to site a biorefinery is a complex decision that depends on many factors, including, but not limited to: proximity to feedstock, cost and availability of suitable land, workforce availability, land use zoning and population density, the availability of emissions offsets, and the availability of water supply. The ISOR provides information, without recommendation, about these constraints. Ultimately, the siting of a biorefinery in California is an economic decision made by proponents; and decisions are made by local permitting authorities, as discussed in Chapter VII and Appendix F. ARB’s future work on sustainability for the LCFS will address how to achieve

sustainable fuels, including achieving sustainable feedstocks and water efficiency of biofuel production.

Comments B-85 – B-109: typographical errors. (PEERREVIEW1)

Response: These typographical errors have been noted and will appear in the errata. These errors are strictly typographical and not substantive in nature.

C. REGULATORY REQUIREMENTS

This section contains comments specifically related to the regulatory language and requirements of the LCFS. This includes comments pertaining to the regulatory text in sections 95480.1 through 95490, such as the CNG and LNG fuel pathways; modified or new fuel pathways for consideration under Method 2A/2B; biodiesel and renewable diesel fuel pathways; carbon intensity due to indirect land use effects and GTAP; miscellaneous comments; administrative facets of the regulation; GREET, lifecycle analysis, and the Lookup Tables; compliance schedule; exemptions and opt-ins; definitions; regulated parties; energy efficiency ratios (EERs); treatment of blendstocks and crude oil; periodic reviews; credit trading; and other regulatory comments. It should be noted that no comments were received pertaining to section 95480 (Purpose).

CNG and LNG Fuel Pathways

C-1. Comment: The approach to fuels developed from waste lacks balance because it does not provide a pathway to produce fuel from processes involving alternatives to landfilling organic materials (i.e. dedicated digesters). (WASTESCT1)

Response: The regulation was modified so that it now has pathways and carbon intensity values for compressed natural gas (CNG) and liquefied natural gas (LNG) from dairy digesters, which are set forth in section 95486(b)(1), Tables 6 and 7.

C-2. Comment: Development of alternative fuel pathways for waste utilization is needed. Over the course of the next year, CARB will dedicate staff and resources to develop fuel pathways for LCFS compliance. These pathways determine what fuels, if any, can be qualified as low carbon fuels under the standard, and also assign full fuel cycle green house gas values. However, CARB staff has suggested that production of new fuel pathways must be initiated by industry members seeking to utilize a particular process for developing fuels. We ask that staff develop this particular pathway to help encourage alternatives to landfilling organic materials. We ask that the Board give staff direction to develop a fuel pathway for fuels from dedicated anaerobic digesters. Without the fuel pathway development process being initiated by staff, it is doubtful that industry members will endeavor to develop a fuel pathway in the near term since the incentives to utilize the landfill gas to CNG pathway are higher absent a pathway for use of digesters. Development of the additional pathway will provide an alternative path for waste to be used, in a manner that reduces landfilling and that further supports the multiple environmental objectives of CARB and AB 32. (WASTESCT1)

Response: In Resolution 09-31, the Board directed staff to work with biofuel producers and other interested stakeholders to identify specialized fuel pathways in a priority list of new pathways to be further developed for incorporation into the Lookup Tables. As a starting point, the Board specifically suggested pathways such as anaerobic digestion,

thermochemical conversion of biomass feedstocks and additional LNG pathways, among others. A draft priority list of such new pathways is to be presented to the Board in December 2009, along with a proposed development schedule.

C-3. Comment: Given the need to modify the current analysis and the need for additional review, we ask the proposed landfill gas to fuel pathway be simply adopted at a later date, analogous to other fuel pathways still under development, after additional technical review and approval by the CARB Executive Officer. In the alternative, we would ask CARB staff to modify the existing fuel pathway prior to adoption on the proposed date. The LCFS regulation is a critical regulation for the state to achieve dramatic emissions reductions and must not be undercut by accounting errors out of the gate. The ARB should also prioritize the development of a fuel pathway for anaerobic digestion as soon as possible. (WASTESCT1)

Response: The regulation was modified so that it now has pathways and carbon intensity values for CNG and LNG from landfill biogas and dairy digesters, which are set forth in section 95486(b)(1), Tables 6 and 7. As noted, in Resolution 09-31 the Board directed staff to work with biofuel producers and other interested stakeholders to identify specialized fuel pathways in a priority list of new pathways to be further developed for incorporation into the Lookup Tables. As a starting point, the Board specifically suggested pathways such as anaerobic digestion, thermochemical conversion of biomass feedstocks and additional LNG pathways, among others. A draft priority list of such new pathways is to be presented to the Board in December 2009, along with a proposed development schedule.

C-4. Comment: First, we would strongly request that in order to be consistent in promoting alternatives to landfilling organic materials, CARB staff should develop the pathway to produce fuel from processes involving these alternatives, including anaerobic digestion (AD). (CWP)

Response: See responses to Comments C-1 to C-3 above.

C-5. Comment: We are writing this letter because the Sanitation Districts of Los Angeles County (Sanitation Districts) are concerned that the menu of waste-to-alternative fuel options that are potentially available is only implicitly and not explicitly recognized in the draft regulation. California generates a broad array and tonnage of waste products. The ability to convert these wastes into creditable alternative fuels for ultimate compliance with the LCFS represents a golden opportunity for a win: win situation—the productive use of waste materials while reducing the transportation sector's overall carbon impact. The proposed LCFS is not particularly waste-based alternative fuel friendly and we think this should be changed. (CSD)

Response: As noted in responses to Comments C-1 through C-4, the regulation was modified so that it now has pathways and carbon intensity values for CNG and LNG

from landfill biogas and dairy digesters, which are set forth in section 95486(b)(1), Tables 6 and 7. As noted in response to Comments C-2 and C-3, the Board directed staff to propose a priority list of new pathways for further development and incorporation into Tables 6 and 7 in future rulemakings, including anaerobic digestion and thermochemical conversion of biomass feedstocks, both of which can be involved in waste-to-alternative fuel pathways. For other pathways using waste feedstocks for which the regulation does not specify a CA-GREET-based pathway, the Method 2A and 2B provisions of section 95486(c) and (d), respectively, may be used to obtain approval of modified or new carbon intensity values and pathways for such fuels through the formal rulemaking process specified in section 905486(f).

C-6. Comment: WM has discussed the importance of the publication of the Biogas LNG LCFS pathway on multiple occasions with CARB staff. We have been assured that this pathway, along with a Fossil LNG pathway, will be published in the very near term. WM would like to reinforce to the Board the importance of this publication and the positive impact it will have upon a brand-new transportation fuel industry. The production of Biogas/Biomethane from landfill waste streams offers one of the lowest carbon intensity fuels currently known to the transportation sector. As mentioned above, WM is nearing startup on a new landfill gas to LNG production facility at our Altamont Landfill in the Bay Area. It is vitally important that CARB publish the Biogas LNG pathway that will allow us to begin generating credits on the very first day of the LCFS program (January 1, 2010). By not publishing this pathway in the very near term, CARB would introduce uncertainty in to this very important new industry. (WM2)

Response: The regulation was modified so that it now has pathways and carbon intensity values for CNG and LNG from North American-sourced natural gas, landfill biogas and dairy digesters, which are set forth in section 95486(b)(1), Tables 6 and 7.

C-7. Comment: Direct staff to make every effort to finish the LNG pathway analysis – before the close of the comment period if possible. Staff work on the analysis is well underway and, we believe, close to completion. (CNGVC1)

Response: See response to Comments C-1 through C-6 above.

C-8. Comment: Conversely, the table also includes remote LNG shipped to Baja, gasified and piped to California for reliquefaction. We believe it is much more likely that any LNG imported to Baja would simply be trucked to California, as included in another of the proposed pathways. We also appreciate that the Board appears to no longer be including remote LNG imported to the Gulf Coast and piped to California as a viable pathway for analysis. (CNGVC1)

Response: The regulation as adopted has a fuel pathway for LNG imported to Baja and then trucked to California, which is set forth in section 95486(b)(1), Tables 6 and 7 (see “Overseas-sourced LNG delivered as LNG to Baja”).

C-9. Comment: Focus first on pathway analyses of LNG from North American sources and from landfill gas. The Board appropriately focused its CNG pathway analysis on North American gas and landfill gas. We believe the focus should be the same for fuel dispensed as LNG. North American natural gas (including gas from the U.S. as well as Canada, see below) is and will continue to be the major source of LNG in California for years to come. The capture and conversion of landfill gas offers a very promising opportunity to reduce significant GHG emissions from landfills and produce an extremely low carbon fuel in the form of LNG as well as CNG. In fact, CNG from landfill gas has the lowest carbon intensity of any fuel analyzed by the ARB. The Board should incorporate these two pathway analyses into the final LCFS. (CNGVC1)

Response: As noted in response to Comments C-1 through C-8, the adopted regulation has LNG pathways corresponding to similar CNG pathways (e.g., there's a CNG and LNG pathway for production of natural gas from dairy digester biogas). Indeed, there are additional pathways established for LNG that are unique to LNG because it involves the additional step of liquefaction that CNG does not require.

C-10. Comment: It is critical that a pathway analysis for fuel dispensed as LNG be completed and incorporated into the rule – if possible, before the end of the 15-day comment period. The state has very few commercially available and cost-effective options for using low carbon fuels in the heavy-duty sector. We are confident the pathway analysis will show that LNG is an LCFS-compliant low carbon fuel. It is in the state's interest that LNG be recognized as quickly as possible as a compliant low carbon fuel. (CNGVC1)

Response: See response to Comments C-1 through C-9.

C-11. Comment: Include relevant pathways and ignore irrelevant ones. The Statement of Reasons (Table IV-4) identifies four LNG pathways under development, but the only identified North American source is Canadian gas pipelined to a liquefaction facility in California. In fact, the only gas piped today into California and liquefied comes not from Canada, but from the Rocky Mountain area. It is essential that Rocky Mountain gas be added as a pathway for California LNG. (CNGVC1)

Response: As noted in response to Comment C-6, the regulation as adopted now has pathways and carbon intensity values for CNG and LNG from North American-sourced natural gas. This includes natural gas from Canada and the Rocky Mountains area.

C-12. Comment: We are concerned that the LCFS, as proposed, does not include dedicated anaerobic digestion of organics to biogas. We are also concerned that the LCFS includes landfill gas, but does not account for fugitive landfill emissions, which distort true carbon impacts. (CCCC)

Response: As noted in response to Comment C-3, the regulation was modified so that

it now has pathways and carbon intensity values for CNG and LNG from landfill biogas and dairy digesters, which are set forth in section 95486(b)(1), Tables 6 and 7. Also as noted, in Resolution 09-31 the Board directed staff to work with biofuel producers and other interested stakeholders to identify specialized fuel pathways in a priority list of new pathways to be further developed for incorporation into the Lookup Tables. As a starting point, the Board specifically suggested pathways such as anaerobic digestion, thermochemical conversion of biomass feedstocks and additional LNG pathways, among others. A draft priority list of such new pathways is to be presented to the Board in December 2009, along with a proposed development schedule.

With respect to the control of fugitive emissions from landfills, such emissions are, by definition, unintended or irregular. Because the LCFS is designed to reduce carbon intensity in a predictable manner from processes with known and regular emissions, the LCFS is an inappropriate mechanism for controlling the fugitive emissions cited by the commenter. Instead, the better approach is to regulate such emissions through a control measure that is specific to landfills, which ARB is currently pursuing. See “Rulemaking To Consider Adoption Of A Proposed Regulation To Reduce Methane Emissions From Municipal Solid Waste Landfills,” proposed sections 95462—95475, title 17, California Code of Regulations (approved by the Board for adoption on June 25, 2009, available for download at <http://www.arb.ca.gov/regact/2009/landfills09/appa.pdf>).

C-13. Comment: No finalized pathway analysis for LNG that reflects domestic pathways, “CNG from domestic sources” is listed on “opt-in” list under §95480, difference in CNG v. LNG production is not significant and TIAX analysis supported by CEC and CARB showed up to a 21 percent reduction in CO₂ equivalent emissions. Finally, natural gas blends with hydrogen and biomethane are not listed and could provide strong support for 2030, 2040 and 2050 LCFS goals. Failure to include these fuels will require Industry to go through an ill-defined process with the Executive Officer, delaying implementation of low and very low carbon fuels. (CE2)

We want you to include “LNG from domestic sources” and the blending of low carbon fuels with very low carbon fuels (e.g., CNG-biomethane, LNG-biomethane, and CNG-hydrogen blends) under the list of opt-in fuels in section 95480. We also want you to finalize the LNG pathway analysis as promised and include domestic fuel scenarios that reflect the current LNG market for transportation.

Response: As noted in response to Comment C-6, the regulation was modified to specify a fuel pathway in section 95486(b) for LNG from domestic (i.e., North American) sources. At the time of its hearing, the Board did not amend the regulation to include blends of the opt-in fuels listed in section 95480.1(b). However, in Resolution 09-31 the Board delegated to the Executive Officer the authority to conduct and complete a rulemaking to add to or amend the list of opt-in, low-carbon fuels specified in section 95480.1(b). Under this directive, the Executive Officer may consider, as warranted, modifying the opt-in list to include blends of the enumerated opt-in fuels.

C-14. Comment: And others have to do with -- we would really like to see domestic LNG analysis done. We think it's a compliant fuel. We do not believe imported LNG may fare well. In fact, it may not be a compliant fuel. But we do certainly think that the domestic LNG should be evaluated. I've been told by staff that it will be. It's coming soon. But I just wanted to assure that we are concerned that it hasn't been to this point. We'd also like to see an evaluation of bio methane blends, not just straight bio methane. (420) (CE4)

Response: As noted above, the adopted regulation specifies a fuel pathway for LNG that includes natural gas from domestic sources, as set forth in Tables 6 and 7 of section 95486(b).

Comments on Methods 2A and 2B

C-15. Comment: (Section 95426, Page 37): There are various processes that may be employed at a facility which would not be accounted for through the variant variables in Method 2A and would not represent a new pathway whereby Method 2B could be used to accurately determine its carbon intensity. In these situations it is not clear how a facility will get approval for a representative carbon intensity value. Since the standard look-up tables do not include much detail, many of the variations will necessitate new inputs which would be prohibited by Paragraph C of Method 2A. For example, a dry mill ethanol facility may have a germ separation process creating an additional co-product for the facility which could result in a lower carbon intensity value. In the current draft this facility does not appear to be able to use Method 2A to determine the carbon intensity value, since the new co-product would be a new input. A second example is where a facility employs geological sequestration for the carbon dioxide generated from ethanol fermentation, significantly lowering the carbon intensity value but also requiring a new input. Both of these examples would require new inputs preventing the use of Method 2A, yet the changes are not significant enough to be considered a new pathway. ADM recommends CARB include a provision allowing for approval of new inputs for unique changes that would meet the "10-10" substantiality requirement but not constitute a new pathway. (ADM)

Response: Changes such as the ones described above would involve new inputs to the CA-GREET methodology, which would therefore make such changes subject to consideration as a new pathway under Method 2B of 95486(d) of the regulation. As specified in section 95486(f)(5), the process for approving either a Method 2A or 2B pathway would involve a formal rulemaking conducted pursuant to the Administrative Procedure Act (Gov. Code section 11340 et seq.). To assist regulated parties and other interested stakeholders, in Resolution 09-31 the Board directed staff to prepare a guidance document (tentatively scheduled for release in December 2009) to aid stakeholders in the process of applying for customized or new carbon intensities using Method 2A or 2B, respectively.

C-16. Comment: Only a limited number of alternative fuel pathways, including corn ethanol, sugar cane ethanol, compressed gaseous hydrogen, biodiesel from soybeans, cellulosic ethanol from farmed trees, average/marginal electricity, and CNG from landfill gas (LFG), have been generated by your staff using the GREET model to estimate the potential energy consumption and greenhouse gas (GHG) emissions of these alternative fuels. Many of these are works in progress and may not include final numbers or important considerations such as evaluation of land use changes (or use of marginal versus prime agricultural land for growing such crop). While we are appreciative of the landfill gas to CNG pathway analysis, this is only one of a large array of GREET pathway analyses that are needed to encompass the attractive options available in the waste-to-alternative fuel arena. The well-to-tank analysis for LFG to CNG shows the largest negative contribution (and therefore the best scenario) to the overall GHG footprint of the alternative fuels analyzed by requiring 814,896 Btu/MMBtu (the energy required to produce a unit of energy of the alternative fuel) and 46.69 gCO₂e/MJ i.e., the lowest (best) overall carbon intensity of the alternative fuels analyzed. The LFG to CNG pathway is a simple yet important example of the benefits of producing fuels from local waste streams. Many other waste-derived alternative fuels should look equally appealing. (CSD)

Response: As noted in response to Comment C-12, the regulation establishes an LFG-to-LNG pathway, as well as other waste-to-fuel pathways. In addition, the Board directed staff to identify other pathways for possible incorporation into the Lookup Tables in the future, including but not limited to other pathways involving anaerobic digestion, thermochemical conversion of biomass feedstocks, and additional LNG pathways.

C-17. Comment: We need other GREET pathway analyses including but not limited to the following:

- a. Landfill gas (LFG) to liquefied natural gas (LNG), pipeline natural gas, electricity, and hydrogen;
 - b. Sewage digester gas (DG) to compressed natural gas (CNG), liquefied natural gas (LNG), pipeline natural gas, electricity, and hydrogen;
 - c. Biosolids to compressed natural gas (CNG), liquefied natural gas (LNG), pipeline, natural gas, electricity, hydrogen and biodiesel;
 - d. Green waste to cellulosic ethanol;
 - e. Fats and grease (collected from restaurants or sewers) to biodiesel; and
 - f. Municipal waste to ethanol; Fischer-Tropsch (FT) diesel; and electricity.
- (CSD)

Response: For comment a., LFG-to-LNG and LFG-to-CNG pathways are established in the regulation. See response to Comment C-12. As noted in response to Comment C-16, the Board has directed staff to identify pathways for a priority list to be considered for future consideration under an ARB rulemaking; these pathways can include the waste-to-fuel pathways suggested by the commenter. Further, as noted

previously, the regulation specifies under Method 2A or 2B the process in which a regulated party can submit to the Executive Officer a proposed new or modified fuel pathway for incorporation into the Lookup Tables in section 95486(b).

C-18. Comment: A variation on most of the alternative fuel feedstock pathways developed by staff that has been overlooked in the proposed LCFS is biofuel crops grown on marginal lands not suited for food crops. The published pathways for cellulosic ethanol from farmed trees via fermentation, sugarcane ethanol and soybean biodiesel should not be the only biofuel crops that are supported within the LCFS. The use of these typical feedstocks have raised a number of concerns such as the consequences of rainforest removal and the diversion of crops to biofuel production that otherwise would be used for the human food supply. Many other biofuel crops can be grown on marginal lands enhanced by biosolids compost and re-used wastewater that overall are much greener operations than their traditional counterparts. Examples of these biofuel crops include:

- a. Biodiesel from sunflower, safflower, winter canola, flax, and camelina;
 - b. Ethanol from grain sorghum and 3-grain mix;
 - c. Cellulosic ethanol from sudan grass; and
 - d. Algae grown in detention ponds (or inside a controlled environment).
- (CSD)

Response: The Board recognizes that biofuels grown on marginal lands not suited for food crops can be beneficial as a source of transportation fuels. To this end, in Resolution 09-31 the Board directed the Executive Officer to work with interested stakeholders to develop criteria and a list of specific biofuel feedstocks that are expected to have no or inherently negligible land use effects on carbon intensity. The Executive Officer was also directed to propose amendments by December 2009, if appropriate, to the regulation resulting from this analysis.

Further, as noted in response to Comment C-16, the Board directed staff to identify pathways for a priority list to be considered for future consideration under an ARB rulemaking; these can include the fuel pathways suggested by the commenter. Moreover, as noted previously, the regulation specifies under Method 2A or 2B the process in which a regulated party can submit to the Executive Officer a proposed new or modified fuel pathway for incorporation into the Lookup Tables in section 95486(b).

Finally, in Resolution 09-31 the Board directed the staff to develop guidelines for applicants to use in proposing new pathways. In the guidelines, the staff is to identify alternative fuels that are not expected to have indirect land use change impacts. The staff is to bring the guidelines to the Board by December 2009. The draft guidelines were presented at a public workshop in August 2009.

C-19. Comment: Staff should develop or at least commit to developing more waste-derived alternative fuel pathways such as the ones listed above so that the

potential fuel developer has an approved pathway (and not just a promise) that it can use to negotiate with the major transportation fuel suppliers. (CSD)

Response: The issue of fuel pathways derived from waste has been addressed in response to Comments C-1 through C-18.

C-20. Comment: The City of San Diego is considering the feasibility of growing biofuel crops on 20,000 acres of marginal land that the City owns. However, there is little incentive in the current form of the draft regulation to offset the massive investment of time, man-power and capital cost that would be required to proceed with this project. A clear GREET pathway analysis by CARB of this alternative could go a long way to developing this resource. (CSD)

Response: The regulation already provides sufficient incentives for the development and use of low carbon-intensity transportation fuels. The Method 2A and 2B provisions of section 95486 may be used to establish the carbon intensity of fuel pathways that could be used to meet the requirements of the regulation. Those provisions could be used by a regulated party to obtain approval of fuel pathways involving the growing of biofuel crops on marginal lands, which could then be incorporated into Tables 6 and 7 in section 95486(b). Moreover, as directed by the Board in Resolution 09-31, staff is developing guidelines to assist applicants in establishing carbon intensity values for new pathways. Fuel providers are expected to preferentially use alternative fuels with the lowest carbon intensity. This will minimize costs in complying with the LCFS and incentivize production of low-carbon fuels.

Each case of growing biofuel crops on marginal lands is unique and may differ from similar cases in significant ways, thereby affecting their overall fuel pathways and associated carbon intensities. Because of this, it was impractical for the Board staff to develop before the April 2009 hearing fuel pathways that are broadly representative of the growing of biofuel crops on marginal lands. With that said, the Board recognizes the merit in encouraging potentially low-carbon fuel pathways, including the growing of biofuel crops on marginal lands. To this end, in Resolution 09-31 the Board directed staff to work with interested stakeholders to develop criteria and a list of specific biofuel feedstocks that are expected to have no or inherently negligible land use effects on carbon intensity. The Executive Officer was directed to proposed amendments to the regulation, if appropriate, resulting from that analysis by December 2009.

C-21. Comment: CARB should establish a pathway for cellulose ethanol from lignocellulosic waste such as straw. While CARB has established fuel pathways for a number of renewable fuels, CARB has not yet established a pathway for one of the most promising technologies for reducing the carbon intensity of fuels—cellulose ethanol from lignocellulosic waste, such as straw. We urge CARB to expeditiously establish a pathway for this fuel. (SHELL)

Response: Although cellulosic ethanol pathways such as those suggested by the commenter were not incorporated into the Lookup Table (Table 6, section 95486(b)(1),

regulated parties and other fuel suppliers could use Method 2B provisions in section 95486(d) to submit a proposed fuel pathway to the Executive Officer for approval as provided in section 95486(f). The Executive Officer's consideration of such a submittal would be conducted pursuant to a formal rulemaking process as specified in section 95486(f). If approved, the cellulosic ethanol fuel pathway could then allow the use of cellulosic ethanol from lignocellulosic waste, such as straw, to help regulated parties meet the requirements of the regulation.

C-22. Comment: It is ICM's opinion that requiring each fuel ethanol producer to calculate the carbon intensity of their product, rather than assigning carbon intensity through lookup tables based on pathways will be a good first step in that direction. If producers were subject to carbon intensity ratings based on averages, there would be no reason for the higher-carbon-footprint facilities to incorporate new technology to reduce their carbon output. Alternately, those producers who were already below the curve would have no incentive to further reduce their carbon emissions. (ICM1)

Response: In Resolution 09-31, the Board determined that the regulation as approved, which includes the Lookup Table approach, uses the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective GHG emission reductions from transportation fuel used in California. The Board also found that the approved regulation encourages compliance with the requirements. In approving the regulation, initial carbon intensity values for various pathways were established. Then, through Method 2A/2B of the regulation, each regulated party or fuel producer can adjust the default value for factors unique to his production and transportation process or obtain approval for entirely new processes.

Producers can take advantage of improvements in carbon intensity, and those producers using fuel with carbon intensity that is lower than its competitors will have a competitive advantage under the LCFS program. As noted previously, fuel providers are expected to preferentially use alternative fuels and blendstocks with the lowest carbon intensity. This will minimize costs in complying with the LCFS and incentivize production of low-carbon fuels.

C-23. Comment: CHOREN is working closely with ARB staff to create a new fuel pathway for "synthetic diesel generated from the gasification of woody biomass." Such "synthetic diesel" has a much lower and cleaner "carbon intensity" value than "biodiesel" or other types of "renewable" diesel - both in terms of its production and its ultimate use. CHOREN is continuing to provide ARB staff all the needed technical information to create a well-supported new pathway. (CHOREN)

Response: No response is required.

C-24. Comment: In the proposed regulations, CARB has only created pathways for the following types of diesel: "biodiesel" and "renewable diesel". (See

Table ES-6). In response to a manufacturer's request, the Executive Officer can appropriately modify the CA-GREET model inputs to reflect specific additional fuel-production processes (Method 2A) or to generate an additional fuel pathway using CA-GREET (Method 2B). CHOREN strongly supports ARB's ongoing efforts to establish these needed additional pathways. (CHOREN)

Response: No response is required.

C-25. Comment: ARB should provide a thoughtful yet efficient and affordable method for stakeholders to propose new or modified inputs for both direct and indirect emissions. Such a process would improve the accuracy of the carbon intensity values while providing an incentive for regulated parties to reduce the direct and indirect emissions associated with their specific fuel pathways. This is particularly important if ARB moves forward with a regulation that includes indirect land use change emissions as currently outlined in the proposed regulation. (CALSTART)

Response: Section 95486(c) and (d) of the regulation set forth the provisions for Methods 2A/2B, which would allow fuel producers to propose and obtain approval for customized or new fuel pathways. Both methods specify the models that must be used to determine both direct and indirect contributions to a fuel pathway's carbon intensity. As noted in response to Comment C-65, the Board determined that the Carbon Intensity Lookup Tables (Tables 6 and 7 in section 95486(b)) must be incorporated into the regulation itself at this time. Because of this, adding to or modifying the carbon intensity values in Tables 6 or 7 necessarily needs to go through a formal rulemaking process conducted pursuant to the Administrative Procedure Act (Government Code section 11340 et seq.).

C-26. Comment: CARB should ensure that the flexibility exists under Method 2A ("Customized Lookup Table") to easily modify key factors so that producers have a clear understanding of how improvements can benefit their carbon score. This can be done by ensuring that under Method 2A (Section 95486(c) of proposed regulations) input factors exist for key variables for the CA-GREET model used to generate the carbon intensity values in the Customized Lookup Table.

The key input variables should mirror the above:

- a. Feedstock specific ILUC impacts.
- b. Pathway specific productivity of biofuel per acre of land (e.g., gallons of biofuel produced per acre of land).
- c. Efficiency of water use (e.g., water per gallon of biofuel produced).
- d. Low carbon agricultural practices that improve the carbon sequestration in soil (e.g., carbon credits for low-till practices).
- e. Creation of protein and electricity co-products (e.g., appropriate crediting for coproduction of protein/animal feed and electricity.) (CALSTART)

Response: Method 2A as approved (set forth in section 95486(c)) already provides

flexibility for fuel producers to calculate unique carbon intensity values for their individual processes and pathways. Method 2A will allow fuel producers to use approved process and pathway-specific values for the parameters that have the greatest effect on the calculated lifecycle emissions. As specified in section 95486(c)(2) and (b)(1), a modified pathway proposed for Executive Officer consideration under Method 2A must use only the inputs that are already incorporated in the CA-GREET model (v.1.8b, February 2009), which is posted on ARB's internet site at http://www.arb.ca.gov/fuels/lcfs/ca_greet1.8b_feb09.xls. This model is readily available for use by regulated parties and other stakeholders, who can evaluate various scenarios to determine the improvements in the CA-GREET inputs that will benefit their carbon scores the most.

With that said, it is ARB staff's intent to continue working with stakeholders to develop specific criteria and transparency provisions for incorporation into the Method 2A and 2B provisions. This would be done so that the Method 2A and 2B process can essentially be turned into an administrative or ministerial process (i.e., an Executive Officer certification process) rather than the current rulemaking one.

C-27. Comment: We believe two additional pathways that do deserve further evaluation are: (a) Domestic natural gas delivered to California from the Rocky Mountain Region and delivered to Southern California utilizing a specific pipeline such as Kern River and liquefied for use as transportation fuel, (b) For imported natural gas (NG) delivery of a 50/50 mix of Russia and Indonesia LNG delivered to the Energia Costa Azul (ECA) Terminal for regasification. The send-out gas will be delivered to California via the existing pipeline network in Mexico. (SEMPRA1)

Response: The regulation specifies fuel pathways for North American-sourced natural gas and overseas-sourced LNG. See response to Comments C-6 through C-8 above. Regulated parties can seek to add pathways that are not yet established in the Lookup Tables (section 95486(b)(1)) through the rulemaking process set forth in either Method 2A or 2B in section 95486(c) and (d), respectively, whichever applies.

C-28. Comment: CARB should work with advanced biofuel producers to ensure timely certification of specific processes under Method 2B Section 95486(d) of the proposed regulations. (EE1)

Response: In Resolution 09-31, the Board directed staff to work with stakeholders, including biofuels producers, to develop guidelines for determining the necessary documentation and an informal screening process for assessing the carbon intensity of new or modified fuel pathways. The Board also delegated to the Executive Officer the authority to conduct and complete rulemakings that will add new or customized fuel pathways and carbon intensity values to the Carbon Intensity Lookup Table in section 95486. These directives will help ensure the timely approval of specific fuel pathways under both Method 2A and 2B in section 95486(c) and (d).

C-29. Comment: CARB's pathways need to ensure that 2nd generation biofuel producers receive fair and accurate carbon accounting for their feedstocks on a timely basis. Critically, the default pathways for advanced biofuels should quantify the benefits of advanced biofuels by including the following:

1. Feedstock specific ILUC impacts – Advanced biofuels should not simply be assigned the same ILUC factor as corn ethanol. The ILUC factor should be specific to the feedstock source and how it was grown. In general, advanced biofuels should have much lower ILUC impacts than corn ethanol. In some cases, a zero impact should be credited for, if, for example, a biofuel is derived from waste materials.
2. Higher productivity of biofuel per acre of land utilized – The ILUC values should reflect the impact of what is likely to be higher productivity for advanced biofuels due to a combination of higher yielding dedicated crops and advanced processing techniques.
3. Efficiency of water use – Reward the use of non-irrigated land and water reduction below prior use. We recognize that this may create a need to equate water usage and GHG production. Fortunately, in California, there are models for the embedded GHG effects of water utilization, and we assume that these or comparable models can be applied in the rest of the country where irrigation is used.
4. Low carbon agricultural practices– Recognize practices that improve the carbon sequestration in soil, including non-till practices and biomass systems, and include appropriate credits in the lifecycle analysis.
5. Creation of protein as well as other feed products such as forage materials and electricity co-products – Recognize the creation of protein/animal feed and electricity, and include appropriate credits in the lifecycle analysis. (EE1)

Response: In Resolution 09-31, the Board directed the Executive Officer to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effects analysis used in the LCFS. The Executive Officer was directed further to return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. The Board specifically stated that the scope of the workgroup's evaluation should include key factors that might impact the land use values for biofuels, including agricultural yield improvements, co-product credits, land emission factors, food price elasticity, and other relevant factors.

Moreover, section 95489 requires the Executive Officer to conduct two reviews of the LCFS program by 2012 and 2015. The reviews must include, at a minimum, thirteen enumerated factors to be considered, one of which is "advances in full, fuel-lifecycle assessments." Because all five of the factors cited by the commenter may contribute to

the indirect effects portion of a full, fuel-lifecycle assessment, they are well within the scope of the two reviews the Executive Officer is required to conduct and may be considered by him/her in those reviews as warranted.

C-30. Comment: Table IV-20 of the “Proposed Regulation to Implement the Low Carbon Fuel Standard” shows eleven different pathways for corn ethanol production. We propose that the pathway list be expanded to recognize advanced energy technologies (combined heat and power, gasification) as well as advanced process technologies (fractionation, corn oil extraction, etc.). The attached study documents the current use of these technologies. (EE1)

Response: It was neither practical nor necessary to establish in the regulation fuel pathways for all the possible variations in production processes for corn ethanol and the other fuels listed in Tables 6 and 7 in section 95486(b)(1) (formerly Tables IV-20 and 21 in the ISOR at IV-50, 51). It was unnecessary to do so because the regulation already sets forth the process (through formal rulemakings) for incorporating in the future modified or new fuel pathways, including those suggested by the commenter. This can be accomplished by fuel producers working with staff to utilize the Method 2A and 2B provisions of Section 95486(c) and (d), respectively, to calculate the carbon intensities of fuel pathways that are of interest. As required by Resolution 09-31, the ARB staff will publish guidelines to assist stakeholders in establishing carbon intensities for fuels under the Method 2A and 2B provisions of the regulation. Resolution 09-31 also delegates authority to the Executive Officer to conduct rulemakings to add new or customized fuel pathways and carbon intensity values, as specified.

C-31. Comment: In addition, the approach to fuels developed from waste lacks balance because it does not provide a pathway to produce fuel from processes involving alternatives to landfilling organic materials. To level the playing field, we ask that the Board give staff direction to develop a fuel pathway for fuels from dedicated anaerobic digesters. Development of the additional pathway will provide an alternative path for waste to be used, in a manner that reduces landfilling and that further supports the multiple environmental objectives of ARB and AB 32. (SIERRACLB2)

Response: See response to Comments C-2 through C-6, C-12.

C-32. Comment: The proposed regulation is missing carbon intensities for biodiesel, renewable diesel, and advanced renewable diesel. As a result, it is impossible to say how much biodiesel or renewable diesel will be necessary to comply with the diesel carbon intensity specification. Since 94 percent – 100 percent of the diesel carbon intensity specification requirements will be met with these fuels, the absence of carbon intensity values for them is untenable. (AB32IMPG2)

Response: The regulation as adopted has fuel pathways and carbon intensities for biodiesel and renewable diesel, as set forth in Table 7 of section 95486(b)(1). As noted earlier in this FSOR, it is ARB’s intent to incorporate before the end of the rulemaking

additional pathways for biodiesel and renewable diesel made from Midwest soybeans. Those additional pathways are being completed and will be released for a supplemental public review and comment period; comments received pursuant to that supplemental period will be addressed in a separate FSOR. As noted in response to Comment C-30, other fuel pathways, including pathways for “advanced renewable diesel,” can be submitted for the Executive Officer’s consideration under Methods 2A and 2B, as provided in section 95486(c) and (d).

C-33. Comment: In Section 95486 of the proposed LCFS, CARB outlines how new fuel pathways will require an Executive Approval to receive a carbon intensity number under Methods 2A and 2B. While we support the intent of these methods, and recognize it provides the flexibility that CARB needs to work with rapidly evolving technologies, we are concerned that this process could create an unintended bottleneck to the commercialization of promising new technologies. (EIN2)

Response: As discussed in Attachment B to Resolution 09-31, incorporation of Tables 6 and 7 (the “Lookup Tables”) into section 95486(b) was deemed necessary to meet clarity and other rulemaking requirements set forth by the Office of Administrative Law. Therefore, new fuel pathways that are to be added to Table 6 or 7 must go through a formal rulemaking process in order to receive approval by the Executive Officer (under the rulemaking authority delegated to the Executive Officer in Resolution 09-31). To help avoid unnecessary delays in the approval process, the Board in Resolution 09-31 directed staff to develop guidelines to assist applicants through the process.

C-34. Comment: The regulation states that the Executive officer must approve the initial request to begin a Method 2B application. CARB should set a maximum timeframe that a regulated party must expect to get this initial approval. (e.g., 15 days). (EIN2)

Response: Section 95486(f) includes a 15 workday timeframe for the determination of an application’s completeness or incompleteness. Once deemed complete, section 95486(f)(4) and (5) requires a public review and final action by the Executive Officer for approval or disapproval of Method 2A or 2B applications to be conducted in accordance with the specific rulemaking timeframes set forth in the Administrative Procedure Act (Government Code section 11340 et seq.).

C-35. Comment: The stipulation in Section 95486(e) that a method be “at least as valid and robust as” as Method 1 could be difficult to meet for new emerging pathways given that Method 1 is based on well established technologies. The science analyzing emerging technologies may be defensible, yet the scientific methods may not be “at least as robust” as those commonly used for Method 1. CARB should consider language such as “best available science”, rather than comparing these emerging technologies better to the well established ones. (EIN2)

Response: The requirement cited by the commenter is necessary to ensure that the carbon intensities of fuels established through Methods 2A and 2B are as reliable as those established through Method 1. It is essential that the carbon intensities of all fuels being used to comply with the regulation be held to the same standard of scientific rigor if the LCFS is to achieve the target greenhouse gas emission reductions. As emerging pathways and technologies get closer to commercial status, it is expected that the scientific methods that will be used to estimate carbon intensities will become as robust and valid as those used for Method 1.

C-36. Comment: CARB has indicated that it plans to use the Executive Officer approval process to screen for environmental safeguards and sustainability. We recognize that this has not been formalized, but urge great attention to how this would be done in conjunction with the new pathways proposed under 2B. For example, CARB should ensure that a producer who is trying to get credit for having made advances in one part of a fuel pathway does not have to subject his entire pathway for sustainability approval if competitors using a default Method 1 number do not have that same requirement. (EIN2)

Response: There are no environmental safeguards or sustainability provisions explicitly set forth in Method 2B (section 95486(d)). However, because the consideration of a proposed Method 2B application must undergo a formal rulemaking (see response to Comment C-34), it is possible that the Executive Officer may receive public comments related to the rulemaking, including environmental safeguards and sustainability. To the extent such comments are received, the Executive Officer will presumably weigh the pros and cons of implementing suggestions submitted by commenters in Method 2B rulemakings to determine the best course of action.

C-37. Comment: However we believe the LCFS has some important shortcomings, and ask the Board to adopt resolutions on the following issues, with our rationale:

- a. Resolution to ensure a streamlined process for new fuel pathway approval.
- b. Resolution to clarify the processes in the case of a change in Carbon Intensity numbers. (EIN2)

Response: Resolution 09-31 has various provisions related to the development of carbon-intensity processing guidelines, an informal screening process, prioritized lists of specialized fuel pathways, and criteria for identifying specific biofuel feedstocks with inherently negligible land-use effects. In addition, the Resolution delegates to the Executive Officer the authority to conduct rulemakings to add new or modify existing fuel pathways and carbon intensity values in the regulation and to add to or amend the list of opt-in low-carbon fuels specified in section 95480.1(b). Further, the Board directed the Executive Officer to monitor the implementation of the regulation and to propose amendments to the regulation for the Board's consideration when warranted. This directive presumably includes proposed amendments intended to streamline the process of incorporating new or changing carbon intensity values in the regulation. In

summary, all these provisions and directives are intended to support the expeditious development and approval of fuel pathways, as well as generally support the LCFS implementation.

C-38. Comment: Efficiency in Fuel Pathway Modification and Development: With this market-minded view of the regulations, we believe that it is imperative that the process for proposing new or modified fuel pathways must be highly efficient. In order for the LCFS to result in more rapid development of sustainable low-carbon fuels, the process must be substantially more dynamic than current programs in which the Air Resources Board verifies and approves emissions reduction technologies. New and modified pathways must be able to address both direct and indirect emissions associated with the pathway in order to incentivize the development and adoption of best practices and technologies. (PRIMAFUEL)

Response: See response to Comments C-30 and C-32 through C-37.

C-39. Comment: Staff believes that GREET input values for industry average practices should be assumed for data that are difficult to obtain and report. Who decides what constitutes “difficult to obtain and report”? Who decides what goes into the “invariant data” list? ARB needs to explain the reasoning behind the concept of the invariant list since we do not support it at this time. (WSPA)

Response: With regard to “invariant data,” the commenter appears to be citing to an earlier draft version of the LCFS regulation that was released for public discussion on December 2, 2008, well before the start of the formal rulemaking process. The language apparently of concern to the commenter has since been deleted and is not present in the adopted regulation. Indeed, the word “invariant” does not even appear in the regulation as adopted. Similarly, the word “difficult” (as well as the phrase “difficult to obtain and report”) could not be found in either the preliminary drafts of the regulatory text that were released for public discussion from March 2008 or the proposed regulatory text released during the formal rulemaking process since March 2009. Neither the term “difficult” nor the phrase “difficult to obtain and report” appears in the regulation as adopted.

C-40. Comment: In furtherance of the technology innovation goals of the LCFS, it is also important to recognize the need for flexibility, especially in the determination of carbon intensity values for novel fuel pathways that are critical to the success of the program. Such cases could perhaps be accommodated by either an expedited rulemaking process or a provision to grant temporary approval until the rulemaking process can be completed. (CHEVRON1)

Response: The issue of expedited or streamlined approvals of new or modified carbon intensity values was addressed in response to Comments C-30 and C-32 through C-37. It should be noted that the Executive Officer can consider, as part of the 2012 and 2015 formal reviews (section 95489) or the ongoing monitoring of the program (Resolution 09-31), enhancements to the LCFS program that can streamline or expedite

the approval process for carbon intensity values and novel fuel pathways.

C-41. Comment: Eventually, CARB will need to evaluate new fuel supply pathways as low carbon fuel production technology improves, and we recommend that staff develop an open and simple process for creating such new pathways in a timely manner. (AAM)

Response: See response to Comments C-30 and C-32 through 37.

C-42. Comment: Mitigation of ILUC impacts is consistent with long-standing precedent established in the California Environmental Quality Act (CEQA) that allows mitigation in some reasonable way. (A2O4NESTE)

Response: No response is required.

C-43. Comment: In summary, the Board should consider directing staff to incorporate dynamic improvements in many land-use variables, as well as revising Method 2A to allow modification of the Lookup Table values. Novozymes has not attempted to identify all of the parameters and variables of the CA-GREET and GTAP modeling that should be revised to reflect continuous improvements and changes in land use and in ethanol production. Novozymes recommends the Board consider the treatment of the many issues identified in other scientific studies submitted to the staff, including the memorandum of February 27 from Liska and Cassmann, et al., and comments filed on behalf of UNICA (with special reference to the dynamic changes in Brazilian land use that are not captured in the Staff Report), RFA and Growth Energy. Incorporating experience curves that annually revise input values will provide a more realistic measure of the carbon intensity of the dynamic ethanol industry. (NOVOVZYM1)

Response: During the implementation of the LCFS, the ARB staff will continue to work to improve the understanding of indirect land use change emissions and the estimation of the emissions. As noted previously, in Resolution 09-31 the Board directed the Executive Officer to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effects analysis of transportation fuels. The Executive Officer was further directed to return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. Moreover, section 95489(a)(3) requires the Executive Officer to consider, among other things, advances in full, fuel-lifecycle assessments as part of the two program reviews built into the regulation. The Board's directives and the regulation's required program reviews will ensure that the LCFS regulation will continue to reflect the dynamic changes in the ethanol industry as well as other fuel sectors.

C-44. Comment: The proposed procedures (Method 2A and 2A) for modifying ILUC carbon intensity values from the lookup tables are not sufficiently responsive to the uncertainties in the ILUC modeling and calculations. The only modifications

to the fixed Lookup Table values contemplated by the Proposed Regulations would be pursuant to so-called Methods 2A and 2B. A producer bears the burden of demonstrating the “scientific defensibility” of alternative calculations used for either Methods 2A or 2B. This burden is unduly heavy and of uncertain application, since there are no standards in the Regulations by which the Executive Officer would determine “scientific defensibility” to overcome the presumptive values incorporated in the Lookup Tables. Moreover, Method 2A, which must be used for producers of existing fuel pathways, limits modifications to the Lookup Table values based solely on modified “inputs ... in CA-GREET,” and may “not add any new inputs (e.g. refinery efficiency).” Method 2B, which is available only for producers of fuels using a “new pathway,” such as cellulosic ethanol, requires a producer to submit a full lifecycle model with fully specified modified parameters for use in CA-GREET. GHG emissions attributable to land-use changes from new pathways must be based on the GTAP model, unless the producer can persuade the Executive Officer to utilize a different model “at least equivalent to the GTAP model.” (BIO)

Response: In Resolution 09-31, the Board determined that the regulation, which was developed using CA-GREET and GTAP models and other GHG estimation techniques, is based on the best available scientific information for estimating the lifecycle GHG emissions for transportation fuels. Because Methods 2A and 2B are intended to be alternatives to Method 1 (the Carbon Intensity Lookup Tables in section 95486(b)), it is necessary to require that Methods 2A and 2B are based on “scientific defensibility” that is at least equivalent to that of the peer-reviewed Method 1. Because of this, the “scientific defensibility” requirement is not unduly burdensome. This requirement is necessary to ensure that fuel producers using either Method 2A or 2B will provide data and information that are valid, relevant, and result in carbon intensity calculations that represent real-world fuel production practices and methods. In short, the requirement will ensure that the GHG emission reduction goals of the LCFS are preserved.

As noted, the Board found that the GTAP model is the best model available for estimating the indirect land use change effects. However, section 95486(c) and (d) permits the use of an alternative to GTAP as part of a Method 2A or 2B application if the Executive Officer determines that the alternative is at least equivalent to the GTAP model. This provision allows regulated parties to propose an alternative to GTAP that better reflects the latest scientific information in the field of land-use change analysis.

With respect to the standards by which the Executive Officer will consider a Method 2A or 2B application, those provisions are set forth in section 95486(c) through (f). This includes a requirement that the Executive Officer’s consideration of the application must undergo a public review process and formal rulemaking conducted pursuant to the Administrative Procedure Act (Gov. Code section 11340 et seq.). This will ensure transparency and consideration of relevant comments submitted by the public and other stakeholders.

C-45. Comment: Thus, while the Proposed Regulations ostensibly afford producers

the opportunity to propose improved models, using updated data based on actual performance, these flexible methods will likely be of limited applicability. The Executive Director is granted broad discretion to reject the use of either new data or new models; the proponent bears the burden of demonstrating the “scientific defensibility” of new models, parameters and data sources; and the controversial CA-GREET and GTAP models are afforded a presumptive accuracy. Together, these factors make it highly questionable whether Methods 2A and 2B will have any vitality in the LCFS program. (BIO)

Response: Because the CA-GREET and GTAP models form the foundation of the LCFS program, it goes without saying that they are presumed to be accurate vis-à-vis Method 2A and 2B. With regard to the potential utility of Method 2A and 2B, it should be noted that the staff is already being approached by potential applicants who want to use the Method 2A and 2B provisions. See response to Comment C-44 for an additional discussion of Method 2A and 2B.

C-46. Comment: The list of corn ethanol scenarios in the gasoline substitutes points to another problem with the approach taken by CARB. The number of permutations for this “one” technology will quickly become overwhelming. In CARB’s lookup table, corn ethanol technology already has ten different permutations reflecting a combination of existing technology options and location options. Even so, these ten permutations do not properly reflect the circumstances of all the individual corn ethanol producers. For example:

- a. Ethanol producers using biomass for heat and power are commingled with those who do not,
- b. Differences in farming practices among feedstock suppliers are ignored,
- c. There is so far no accounting for emerging corn ethanol technology options,
- d. No accounting for diesel fuel substitution.

If the biofuels industry is to rely on the default analyses provided by CARB, then CARB is faced with the prospect of producing many more permutations on the technology options than has so far been produced. It may not be practical to rely on such default analyses. Instead, it will be important for regulators to offer flexibility in allowing companies to offer their own documentation and modeling of the specific conditions reflected in their fuel pathways and technology choices. Finally, the arbitrary distinction between gasoline and diesel markets does not allow CARB to account for the reduced emissions of introducing clean diesel vehicle technology and clean diesel fuel substitutes in the light and medium duty markets assumed to be served exclusively by gasoline. While CARB gives credit to hydrogen and electric vehicle technology for its inherent efficiency improvements, it ignores this benefit in the case of light duty and medium duty diesel vehicle technology. (BIO)

Response: The fuel pathways specified in Carbon Intensity Lookup Table 6 (section

95486) for corn ethanol cover the production processes that are most commonly used. The parameters that most affect the carbon intensity of the ethanol are reflected in the different pathways. Fuel producers using production approaches or practices not shown in the Lookup Tables can develop their own production pathway using the Method 2A or 2B provisions of the regulation. Rather than being a problem, this approach provides flexibility to the industry and spurs innovation by encouraging producers to generate additional pathways based on the use of lower GHG technologies and processes. And contrary to the commenter's claim, adding more permutations into the Lookup Tables will not be overwhelming; there is no physical limit to the size of the Lookup Tables, and the regulation can simply be amended through rulemakings to enlarge the Lookup Tables as needed.

Because the LCFS standard for diesel fuel is separate from gasoline, it is not necessary to provide additional credits to diesel vehicles for having greater fuel efficiency than for gasoline vehicles. The regulation does not include a credit for diesel fuel used in light duty vehicles that would substitute for gasoline vehicles because the ARB does not want to incentivize the replacement of gasoline vehicles with diesel vehicles because of diesel's greater emissions of particulate matter and other criteria pollutants. In Resolution 09-31, the Board found that crediting light-duty vehicles for reduced carbon intensity in the regulation is inappropriate because it would not provide any significant long-term benefits of promoting significantly lower carbon fuels and significantly more energy efficient vehicles.

C-47. Comment: Integrated strategies involving co-production of food & fish in conjunction with oil seed trees & intercropping is very difficult to model within the current GREET CA model. The example above requires changing many assumptions now used in looking at "land use change", "indirect land use change" and other variables now in models based on an assumption that increased biodiesel or renewable diesel demand will lead to expansion of only traditional oil seed crops. We recommend that CARB and/or California Energy Commission staff work together to develop a specific guidance document for the oil seed industry that suggests best practices for co-planting of oil seed trees with food crops to optimize the production of both food and fuel and to minimize the life cycle carbon impacts of oil production. We are suggesting this not to promote any specific trees or crops, but to encourage CARB to make changes in the GREET CA model and any implementation of the LCFS to consider an integrated approach to production of both food and fuel. This will optimize carbon benefits and help provide solutions to what is seen as a perceived barrier to investment in the biofuels sector and sustainability of biofuels. This guide would be used by the oil seed industry in looking at how to produce vegetable oil in a way that leads to the best possible food supply and carbon life cycle results. (CO2STAR)

Response: As noted, in Resolution 09-31 the Board directed the Executive Officer to:

1. Convene an expert workgroup to assist the Board in refining and improving the land use and indirect effects analysis of transportation fuels and return to

the Board no later than January 1, 2011 with recommendations or proposed amendments, if appropriate; and

2. Work with stakeholders to prepare guidelines to assist regulated parties in determining the data, documentation, and other information needed to support the expeditious development of carbon intensity values for new or modified fuel pathways.

In addition, the two program reviews built into section 95489 can also provide an opportunity to investigate the commenter's suggested guidance document. The suggested guidance potentially falls within one or more of these follow-up activities, so the suggestion can be considered during the program's implementation as the Executive Officer deems appropriate.

C-48. Comment: What is important in regulation of carbon emissions from transportation fuels is the carbon or other greenhouse gas emissions after the fuel is burned that come out of the tailpipe and affect climate change. This is the issue that is being addressed environmentally, not the need for alternative fuels or dependence on petroleum or economic benefits. We understand that CARB staff was given the task of evaluating carbon life cycle emissions of the various biofuel or alternative fuel options as an incoming fuel. This was done by comparing all alternative fuels on a Mj/kg of fuel. While this does provide a basis for understanding the different characteristics of fuel at an energy level when burned as a pure fuel, the difficulty in real life is that fuel acts very differently when it is blended at a low blend as demonstrated from various studies of the following fuels:

Biodiesel:

One of the characteristics of biodiesel that make it different from diesel fuel is the presence of additional oxygen atoms. This can create stability problems and other issues in transport and storage. But it also means that there are extra oxygen molecules available at the time of fuel burn. While the latest generation of diesel engines have very sophisticated oxygen sensing systems and automatic adjustments, this is hardly true of the average diesel engine in the fleet. The other variable is lubricity. New Low Sulfur Diesel fuel has much poorer lubricity. This is compensated with lubricity additives. Unfortunately the additives are not perfect and can come out of solution, especially in very cold weather. Poor lubricity can then affect fuel economy due to increased friction losses. Several studies can be cited to help document this effect. National Renewable Energy Lab (NREL) with work done by Bob McCormick documented about a 1/2 percent improvement in fuel efficiency from use of 5 percent biodiesel in diesel engines, with a neutral impact at a 20 percent blend and then a decline in efficiency due to the lower energy content (somewhere between 8 percent or 10 percent depending on which studies are used). A study by the University of Saskatoon in Saskatoon, Saskatchewan saw even greater fuel efficiency gains from a 2 percent blend of biodiesel (as much as 1-3 percent). While the Saskatoon

study may not be as relevant because of the poor lubricity standards of Canadian diesel fuel it does indicate a trend. Numerous studies are now underway following up on the introduction of low sulfur fuel that seem to document the same fuel efficiency loss from the reduction in the lubricity of the fuel. This includes studies being undertaken by CARB staff and various consultants to measure and confirm the exact efficiency benefits or losses of low blends of biodiesel. This issue is very important in understanding the net fuel efficiency and carbon benefits of biodiesel. Right now, using a Kj/kg comparison of the fuel biodiesel is given a 10 percent reduction in efficiency based on an assumed use of 100 percent biodiesel. In fact, market share of B-100 nationally is much less than 1 percent and even when B-20 is included the market share of biodiesel sold as anything other than a 2 percent or 5 percent blend is very low. This trend is likely to continue in the future, since the driving force behind use of biodiesel is the National Renewable Fuel Standard, which requires use of renewable fuels on an increased percentage basis starting at 1/2 percent in 2010 and moving to 1 percent by 2012 and higher percentages up to 2022. So while 99 percent of the market is a low blend fuel of 2-5 percent, the assumed energy content of the fuel is for a 100 percent biodiesel. So how does this affect the life cycle carbon emissions of biodiesel? If you apply a 10 percent energy efficiency loss on a pro-rata basis to 5 percent biodiesel it means there is a 1/2 percent loss of fuel efficiency at 5 percent. Yet the NREL studies show a 1/2 percent gain in fuel efficiency. This represents a 1 percent difference in the net carbon emissions benefit of biodiesel (from a 1/2 percent penalty in efficiency in the GREET CA Model to a 1/2 percent gain in NREL studies). So how would this affect the calculated life cycle carbon emissions if emissions were measured at the tailpipe? Lets say that biodiesel has a life cycle carbon emission benefit of 60 percent using the GREET model and incorporating the 10 percent fuel efficiency loss (this would of course depend on the feedstock and assumptions made in production but we are using this number to keep the math simple). Now let's say that there is instead a 1/2 percent gain from a 5 percent blend. This difference in efficiency immediately improves the carbon benefit of the fuel by 20 percent (1 percent efficiency gain from a 5 percent blend of fuel means a 1/5th or 20 percent impact). So the biodiesel that achieves a 50-60 percent life cycle benefit in the GREET CA model would instead have an 70-80 percent life cycle carbon benefit.

Ethanol:

Ethanol does not have any of the oxygen or lubricity benefits at low blends (and a 10 percent blend is assumed in the baseline fuel) and has a more significant energy loss (30 percent). At the same time, there is a significant improvement in octane, which can greatly impact vehicle performance in higher ethanol blend levels, particularly if the vehicles are tuned to consider this higher octane. This is not done in any gasoline vehicles in the USA, including E85 vehicles, because very few of the flex fuel vehicles are using E85 in real life because of the lack of infrastructure for ethanol and the higher cost of ethanol in the USA. This may change very quickly if ethanol is less expensive than gasoline and there are a lot

of flex fuel vehicles on the market. In Brazil, over 90 percent of new cars are flex fuel and alcohol use in new cars is much greater than gasoline, with a trend that suggests that very little gasoline will be sold to truly flex fuel vehicles as long as the price difference of ethanol in the Brazilian market remains in place (alcohol is about 10 percent cheaper even when accounting for energy loss). What is more important from a carbon perspective are the changes made to new vehicles after they are sold. Right now the auto makers still tune flex fuel vehicles in Brazil to optimize for gasoline, since performance on gasoline is a little better and performance is what sells cars. However, fuel costs are what drive long-term behavior. Most Brazilian owners of new cars elect to adjust their timing to optimize for ethanol, thereby eliminating much of the energy loss inherent in the fuel and taking advantage of the full octane and other burn benefits of the fuel. A rule oriented to carbon emissions at the tailpipe would provide a strong incentive for auto makers to tune vehicles to ethanol in the event it is cheaper in the California market in the future and flex fuel vehicles dominate the new car market. While this may not appear imminent, volatility in petroleum prices and the EPA fuel efficiency credits associated with E85 vehicle manufacturing make it likely that both the vehicle fleet and fuel infrastructure could develop and if fuel and alcohol prices are very different, California drivers are likely to duplicate Brazilian behavior. Furthermore, if car companies can get credit for these timing adjustments in new cars, the energy losses now true with ethanol could be partly eliminated.

Mixed Alcohol and BioButanol:

Properties in mixed alcohol (a mix of alcohols) and BioButanol also can affect the fuel efficiency of gasoline in different blends and consideration of this affect in looking at renewable fuel life cycle carbon benefits is important and could be an important incentive for petroleum companies blending in these fuels. Most of these fuels result from cellulosic sources of biomass and have excellent life cycle carbon benefits as pure fuels anyway. BioButanol does not have any energy loss vs. gasoline and is likely to have a significant impact on fuel efficiency in low blends (we do not have all the study data to be able to corroborate this but discussions with various people have suggested this is true). (CO2STAR)

Response: With respect to biodiesel, the commenter points out specific concerns and performance issues that are beyond the scope of the LCFS regulation because the LCFS does not, by itself, establish any motor vehicle fuel specifications. In other words, the LCFS does not replace or modify other motor vehicle fuel specifications. Engine performance issues with biodiesel, such as those raised by the commenter, are best considered during ARB staff's upcoming development of biodiesel and renewable diesel specifications for motor vehicle fuel. In Resolution 09-31, the Board directed staff to propose such fuel specifications by December 2009, as appropriate. Due to recent delays and the need to conduct follow-up environmental impacts testing in the biodiesel/renewable diesel testing program, the staff is expected to propose such biodiesel/renewable diesel fuel specifications to the Board in mid-2010.

Similarly, with regard to ethanol, the commenter's suggestion that the regulation provide credit for automakers to tune their vehicles specifically for ethanol goes beyond the scope of the LCFS regulation. This suggestion is best addressed as part of ARB's Low Emission Vehicle program, which sets forth specifications and other requirements applicable to the automobile manufacturers.

And, with regard to mixtures of ethanol and biobutanol, the use of biobutanol in motor vehicle fuel in California is not currently allowed. This is because neither the ARB nor the Division of Measurement Standards has promulgated standards or other requirements on such fuels. Thus, in order to sell such a fuel in California, the fuel provider would need to seek the promulgation of a motor vehicle fuel specification for biobutanol. In ARB's case, that would require, among other things, a multimedia evaluation conducted pursuant to Health and Safety Code section 43830.8.

C-49. Comment: While the market conditions are not yet ideal for a flex fuel vehicle in the US optimized for ethanol, mixed alcohol or biobutanol, this could change in a 2-3 year time period. We suggest you look at possible incentives for optimizing the energy benefits from timing adjustments in flex fuel cars by determining if there are studies being done in Brazil evaluating the fuel economy of ethanol in new cars that have timing adjusted for ethanol vs. gasoline. This could be used to consider various incentives that could be offered to auto companies to get vehicles optimized for ethanol fuel efficiency in the event ethanol is much less expensive and readily available, as is now true in Brazil. These incentives could include mixed alcohol and bio-butanol. (CO2STAR)

Response: See response to Comment C-48.

C-50. Comment: The best example we have for this strategy is a program being implemented by Sustainable BioBrazil in conjunction with the State of Maranhao to plant 1 million hectares of agricultural land with Macauba in conjunction with small producers (and with parallel planting on small producer lands). Macauba is a native oil seed tree common to all of Latin America, with high concentrations of natural tree production in many parts of Brazil. Studies by EMBRAPA and other research organizations show very high yields per hectare (4-5 tons of oil) and the potential to increase the yields through genetic selection. In addition the plant produces another 10 tons per hectare of a biomass for energy production and 10 tons of animal meal. The main reason we mention this example is that the same tree allows for planting of crops or grass between the trees because of the height of the canopy and type of foliage that allows for good light penetration between trees (unlike West African palm). (CO2STAR)

Response: Section 95486(c) and (d) (Method 2A and 2B) provide mechanisms for a fuel provider to obtain recognition of the fuel pathway suggested by the commenter.

C-51. Comment: We also want to emphasize that the example we have noted above

is not just a research example. There is commercial production of macauba oil seed trees and processing of fruit clusters to produce oil for use in soap and cosmetic applications, meal for animals, biomass for steam production and other by-products. This is occurring in a plant in Mato Grosso de Sol in Brazil. The planting cost for the tree is low and harvest is very simple (fruit clusters can be harvested with the same cluster cutting knives used in West African fruit bunch harvests). It does not require the large amount of rain needed by West African palm, meaning it can be grown in most of Latin America. We anticipate that the land cost, oil seed tree planting and harvest cost will be much lower than the average cost for West African palm, which already has a low production cost (estimated at under \$300 per ton of oil per hectare in many studies). There has been testing of macauba oil by Dr. Miguel Dabdoub of Biodiesel Brasil confirming that it is an excellent oil for biodiesel. This means issues of fruit harvest, movement of fruits to plant, plant design, construction and processing have all been solved and the product is commercial. In addition, the tree fruits for up to 100 years and can be grown in existing pasture land without reducing significantly any pasture for cattle or other animals (because palm fronds are smaller and less dense and allow a significant amount of light to penetrate to a ground level, unlike West African Palm). (CO2STAR)

Response: See response to Comment C-50.

C-52. Comment: CBA urges ARB to develop and publish LCFS fuel pathways for biodiesel produced in California and for biodiesel using waste feedstocks such as used cooking oil and inedible animal fats. (COI)

Response: The regulation was modified to set forth fuel pathways for biodiesel from used cooking oil (Table 7 in section 95486). Table 7 was also modified to establish a pathway for renewable diesel made from tallow. As noted previously, it is ARB's intent to add a fuel pathway for biodiesel and renewable diesel made from Midwest soybeans before the end of this rulemaking. In future rulemakings, other fuel pathways can be developed by the staff and or by regulated parties and other applicants under the Method 2A or 2B provisions of section 95486.

C-53. Comment: Finalize the LNG pathway analysis as promised and include domestic fuel scenarios that are reflective of the current LNG market for transportation. (CE2)

Response: See response to Comments C-6 through 11, C-13, and C-14.

C-54. Comment: And the third point I want to make is that oil sands, which is upgraded in Alberta, is particularly suited to transportation fuels and has lower refining emissions than other crudes that are used. And you need to take that into account as you look at the oil sands crude if you want to get the right life cycle comparison. So if I can just take five seconds and recommend that you recognize these three points and remove the exclusion of oil sands crude from

the common basket in California. (CAPP2)

Response: The ARB staff is currently developing a pathway analysis for oil sands that will include the processing and transportation emissions. If appropriate, that pathway may be incorporated into the Lookup Tables in section 95486 in a future rulemaking.

It should be noted that oil sands-based crude was neither refined in California in 2006 nor otherwise present in the 2006 baseline crude mix in significant amounts. As part of the program reviews mandated in section 95489, the Executive Officer will evaluate changes to the California baseline mix over time. As crude from oil sands is imported into California in larger amounts, the carbon intensity of the baseline crude mix may change over time, which may necessitate a change in either or both the baseline mix's carbon intensity and the LCFS' compliance schedule.

From the fuel provider's perspective, the regulation was modified so that Method 2B under section 95486(b)(2)(A)2.a.ii.II provides a mechanism for establishing carbon intensity values for fuels derived from high carbon-intensity crude oil (e.g., some types of oil sands).

Comments on Biodiesel and Renewable Diesel

C-55. Comment: Complete the unfinished work related to the diesel portion of the program before adopting a diesel carbon intensity standard. The Staff Report states that there are no proposed carbon intensity values for biodiesel or renewable diesel, that the economic analysis of the proposed diesel specification is based upon preliminary carbon intensity estimates that the staff thinks are significantly wrong, that a multi-media analysis for biodiesel is not complete, and that the fuel specification for biodiesel will likely be revised in the near future. Under these circumstances, the Board should finish the homework before adopting a diesel carbon intensity specification. (AB32IMPG1)

Response: The regulation was modified to specify fuel pathways and carbon intensity values for biodiesel and renewable diesel in Table 7 of section 95486(b). As noted in response to Comment C-52, it is ARB's intent to add a fuel pathway for biodiesel and renewable diesel made from Midwest soybeans before the end of this rulemaking. With regard to the economic impacts analysis in the Staff Report, that analysis relied on projected compliance scenarios and known technologies for producing biodiesel, neither of which relies on the separate analysis to determine the carbon intensity of a biodiesel fuel pathway. Finally, because the LCFS does not, by itself, establish a motor vehicle fuel specification, completion of a multimedia evaluation pursuant to Health and Safety Code section 43830.8 was not required prior to adoption of the LCFS regulation. See ISOR at V-26 through V-33.

C-56. Comment: Complete all incomplete life cycle analyses (LCA), so that the carbon intensity of all applicable fuels is known, and the feasibility and supply and cost impacts of the rule can be adequately considered. The LCFS Staff Report states

that the carbon intensity values “represent the currency on which the LCFS is based.” The staff report does not include any carbon intensity values for biodiesel or renewable diesel products, and lists several additional carbon intensity values that have yet to be calculated. These carbon intensity values should be established by Board action and included in the LCFS regulation, rather than left for the staff to fill in the blanks later. (AB32IMPG1)

Response: See response to Comment C-55. Also as noted previously, Resolution 09-31 directs staff to identify priority pathways to be developed. Staff will present its recommendations to the Board in December 2009.

C-57. Comment: Until the carbon intensities of the various biofuel pathways are known, it is simply impossible to determine the feasibility of the standards since biofuels are likely to be a key component of compliance with the standards especially in the short term. (SHELL)

Response: In Resolution 09-31, the Board concluded that the regulation was based on the best available scientific and economic information and that the regulation was sufficiently supported to be approved by the Board. In the Lookup Tables 6 and 7 (section 95486(b)(1)) and the associated supporting fuel pathway documents, the carbon intensities of fuels that will likely be used to meet the requirements of the LCFS are documented with a sufficient degree of knowledge to enable a sound and defensible feasibility assessment of the standards. With regard to the specific biofuels, biodiesel and renewable diesel, the regulation was modified to set forth fuel pathways and carbon intensities for various pathways leading to biodiesel and renewable diesel.

C-58. Comment: The City of Inglewood supports adoption of the LCFS. One percent reduction could be achieved with 31 to 35 mgpy of California produced biodiesel made from waste feedstocks such as animal fats and used cooking oils (the latter is based on an LCFS pathway for biodiesel produced in California using inedible animal fats and used cooking oils achieving a 70 percent and 80 percent reduction respectively in carbon intensity versus the current petroleum diesel baseline of 94.71 gCO₂e/MJ). (COI)

Response: No response is required.

C-59. Comment: As the LCFS is currently structured, it does not encourage the use of biocrude oil in refineries. California has billions of dollars of existing functioning large scale oil refining hardware which could be used to process biocrude to make future consumer fuels. The use of these available facilities to process biocrude should be encouraged to minimize fuels costs to California consumers and to do so these refinery assets must be maintained. Refiners should have the option of using biocrude feedstocks to achieve the LCFS standard rather than having to blend in products manufactured from new expensive biorefineries. (PP1)

Response: The regulation as adopted provides sufficient incentive for the use of all transportation fuels with low-carbon intensity values. Fuels produced from biocrudes will be incentivized if they have carbon intensity values that are lower than their petroleum counterparts. Refiners will be allowed to use whatever crude feedstocks they desire to produce their fuels as long as the fuels' carbon intensity values comply with the requirements of the regulation. Therefore, under the regulation, refiners would have the option of using biocrude feedstocks if they desired.

Comments Related to Indirect Land Use Effects and GTAP

C-60. Comment: GTAP values will vary depending on the customized look-up table values created using Method 2A and Method 2B. Utilizing Method 2A and differentiating an ethanol facility from that in the standard look-up table will yield a separate GTAP value than that of the constant value listed. GTAP should be dynamic enough to account for such variables as co-product differences and carbon sequestration. A standard value placed in CA-GREET 1.8b for a process will not describe the uniqueness of a customized carbon intensity value. GTAP will also need to have the capacity to evaluate new pathways that are generated using Method 2B. (ADM)

Response: The GTAP model can account for differences in the values of many input variables. Also, the staff is capable of adjusting the GTAP model predictions for differences in the values of many variables. Differences in co-product values and the amount of carbon sequestration are two such variables that can be considered. The staff will consider changes to the values of any variables that influence the emissions from the indirect land use effects if the applicant can demonstrate that such changes are scientifically warranted.

The above notwithstanding, modified or new fuel pathways submitted pursuant to Method 2A or 2B, respectively, for consideration by the Executive Officer would need to undergo the formal rulemaking process set forth in section 95486(f). In Resolution 09-31, the Board delegated to the Executive Officer the authority to conduct rulemakings to revise any existing fuel pathway or carbon intensity value except values based on land use or other indirect effects that are specified in the Lookup Tables in section 95486 as adopted in this rulemaking.

C-61. Comment: We encourage the California Air Resources Board (CARB) to consider more effective mechanisms than ILUC for controlling GHG emissions including application of a low carbon standard to all goods and services in our economy, both domestically produced and imported. In this way we can reduce GHG emissions while encouraging development of biofuels technologies, which have so much potential to reduce dependence on imported petroleum and help mitigate global climate change. (ISU1)

Response: The Board's approval of the LCFS regulation, based in part on the analysis of indirect land-use change effects (ILUC), reflects the Board's determination that the

regulation uses the most effective and scientifically defensible approach for achieving the emissions reductions required by the Governor's Executive Order and AB 32. A single standard applying to all goods and services produced domestically and imported would not be technically and administratively feasible.

C-62. Comment: If CARB includes ILUC factors, CARB should clarify the regulations to ensure that the processes that exist for biofuel producers to establish unique carbon intensities for their fuels also apply to the ILUC factors. It may be, for example, that the feedstock used by a particular biofuel producer is produced in a very sustainable way (e.g., on marginal land) that does not contribute to land use change. In that case, the regulations should allow the producer to petition CARB for a unique carbon intensity for the fuels that they produce. (SHELL)

Response: The process suggested by the commenter is already incorporated into both Method 2A and 2B in section 95846(c) and (d), respectively. No further changes are required. The above notwithstanding, the Board in Resolution 09-31 directed the staff to identify fuel pathways that may have no significant indirect land use change impacts. The staff made an initial listing available for comment in August 2009. The staff will continue to work with stakeholders to refine the list. This was part of the draft guidelines (also being developed pursuant to Resolution 09-31) for applicants to use in developing and submitting applications for new pathways.

C-63. Comments: We urge the ARB to develop a fair, robust, and open science- and data-based metric, as well as opening the ARB process to other models and methodologies other than GTAP, to evaluate indirect land use change for all fuels that will be evaluated with the LCFS. (111SCIENTISTS)

Response: The regulation as approved by the Board already provided for the Executive Officer to allow the use of alternatives to GTAP that are shown to be at least equivalent to GTAP. Because of this, the regulation as adopted includes a fair, robust, and open science- and data-based approach for evaluating the carbon intensity of transportation fuels. As determined by the Board in Resolution 09-31, the GTAP model is the most appropriate and scientifically valid model available for estimating the indirect land use change effects of the transportation fuels that will be used to meet the requirements of the regulation. However, the Board recognizes that the science of land-use change analysis continues to evolve, and the regulation may need to be updated in the future to reflect such developments. Therefore, pursuant to Resolution 09-31, the staff will continue to work with stakeholders to evaluate other models and approaches that could be used to evaluate the indirect land use change effects. The Board directed the staff to establish an expert workgroup to evaluate the approaches for estimating the indirect land use effects impacts.

C-64. Comment: Given the limited time, a reasonable solution to the challenges discussed above is to submit an LCFS regulation based on direct carbon effects (including direct land use impacts) and support a rigorous 24-month analysis of the indirect, market-mediated effects of petroleum and the entire spectrum of

alternative fuels, regardless of source. The analysis could be conducted in collaboration with other institutions and governments implementing carbon-based fuel standards, and should include a consideration of the best way to prevent carbon effects outside the primary system boundary, including promoting sound land use practice with more direct policy solutions. This approach is consistent with the principle that all fuels should be judged through the same lens in a performance-based standard, as well as the approach taken by the European Parliament. It is worth noting that an LCFS policy based on direct effects already favors non-land intensive, advanced biofuel production over conventional biofuel production. (111SCIENTISTS)

Response: Despite the difficulty and the uncertainty involved, in Resolution 09-31 the Board found that indirect land-use change has been appropriately included as part of the lifecycle analysis conducted by staff. Essentially, the Board determined that in order for the regulation to be scientifically valid, it is essential that the LCFS include indirect effects, where present, for biofuels. With that said, the Board recognizes that the science of land-use change analysis continues to evolve, and the regulation may need to be updated in the future to reflect such developments. Therefore, the Board directed staff to convene an expert workgroup to develop recommendations for refining land use change modeling and return to the Board with those recommendations, if appropriate, by January 1, 2011. The staff will continue to work with stakeholders to better understand the indirect emissions effects for all fuels, and will make any necessary changes to the regulation to ensure that the regulation is based on the best science available.

With regard to sustainability, in Resolution 09-31 the Board directed the staff to work with various stakeholders to present a workplan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation. The workplan is required, among other things, to contain a proposed schedule for finalizing the sustainability provisions by no later than December 2011, unless the Executive Officer determines that such actions are not feasible and not appropriate.

C-65. Comment: Currently, the proposed regulation suggests basing carbon intensity on values in lookup tables for specified pathways. The lookup tables will be developed and modified based the California Energy Commission modified GREET model (called CA-GREET) and the Purdue University Global Trade Analysis Project model (GTAP) for indirect land use change (ILUC) carbon intensity adders. In both cases, it is clear that model results will rely heavily on CARB assumptions and pathway databases contained within the models. These models are subject to frequent change and updating. The proposed regulation states that regulated parties may obtain CARB approval to either modify the CA-GREET model or to generate additional pathways using CA-GREET after a public process. Having spent the better part of a year in developing an up-to-date, user-friendly, business carbon model (the ICM Econergy Model), ICM's past experience is that any such pathway and lookup table change driven by any carbon model (e.g., CA-GREET) will be at the discretion of the CARB staff or

third party contractors retained by CARB to provide model and database recommendations. Any change would also require lengthy public hearings. Experience has shown this to be impractical. Carbon intensities of plant-specific ethanol must be as up-to-date and real-time as possible to recognize real time improvements in agricultural practices, chemical use, crop yields, and improved plant production processes. We believe that no carbon accounting model should be ever be approved or even endorsed by CARB, including the ICM Econergy Model. If any carbon accounting model contains all the required elements and pathways, and the calculations and outputs can be verified by CARB, a model should be allowed for use as a tool to determine carbon intensity in what will become a fast-paced carbon trading market. Because the U.S. looks heavily at the precedents set by CARB in establishing national legislation, ICM supports CARB oversight, but not potential regulatory obstructions to efficient business. (ICM1)

Response: Contrary to the commenter's position, in Resolution 09-31 the Board determined that the regulation, which is based primarily on the use of CA-GREET and GTAP, represents the best available scientific data and information. The Board therefore approved the use of the GREET and GTAP model approaches for calculating the carbon intensity of transportation fuels. While no model is perfect, these models reflect the most scientifically defensible approaches for calculating the carbon intensity of various transportation fuel pathways. This was generally confirmed by the four scientific peer reviewers who reviewed the scientific portions and bases of the regulation pursuant to Health and Safety Code section 57004.

With that said, the Board recognizes that the science underlying both CA-GREET and GTAP continues to evolve, and the regulation may need to be updated in the future to reflect such developments. Therefore, the Board directed staff to convene an expert workgroup to develop recommendations for refining land use change modeling and return to the Board with those recommendations, if appropriate, by January 1, 2011. Also, two program reviews are mandated under section 95489 by 2012 and 2015. These program reviews will cover, among other things, both the direct (i.e., CA-GREET) and indirect (i.e., GTAP) aspects of the lifecycle modeling. During the implementation of the LCFS, the Board directed the staff to continue to work with stakeholders to ensure that the most valid models are used to estimate carbon intensity of transportation fuels and that the models include the most recent and accurate data, assumptions and calculation methodologies. As directed, the staff will propose any needed amendments to the regulation to ensure that the LCFS includes the most accurate carbon intensities possible for transportation fuels.

With regard to the need for public hearings to make changes to the Lookup Tables, this was done specifically to address concerns about the approvability of the regulation. As discussed in Attachment B to Resolution 09-31 and in the First 15-Day Change Notice, staff became concerned that under the original proposal, the Executive Officer's action of certifying carbon intensity values could have the effect of establishing an important element of the regulation without following the rule-adoption process or applying robust

criteria in the regulation that significantly narrow the Executive Officer's discretion in certifying carbon intensity values. This could have resulted in disapproval of the mechanism by the Office of Administrative Law. Concerns were also raised that, as initially proposed, the certification process might not be sufficiently transparent.

Accordingly, the Board agreed with staff's recommendation, and section 95486 was modified to make the Lookup Table and its carbon intensity values part of the regulation. While the carbon intensity values could only be amended or expanded by regulatory amendments, in Resolution 09-31 the Board delegated to the Executive Officer the responsibility to conduct the necessary rulemaking hearings and take final action on any amendments, other than amending indirect land-use change values included in the Lookup Table as adopted in this LCFS rulemaking. This is appropriate because of the technical nature of the carbon intensity determinations and the need to expedite the amendment process. Staff intends to develop for consideration by the Board in December 2009 specific guidance on establishing carbon intensity values that, if feasible, could become part of a certification process.

It should be noted that, in addition to the Board's directives and the two mandated program reviews, the regulation already provides mechanisms for regulated parties to get the most current information applicable to the various fuel pathways reflected in the regulation. To do this, regulated parties would need to submit their process-specific information pursuant to the mechanisms set forth in Method 2A and 2B of section 95486(c) and (d).

C-66. Comment: To create a thorough and efficient process for proposing new or modified pathways CALSTART commends ARB staff for including in the regulation processes for modifying model inputs to reflect specific processes (Method 2A) and for creating new fuel pathways (Method 2B). CALSTART believes it is imperative that these processes apply to indirect emissions as well as direct emissions. The language in the ISOR refers only to new or modified inputs for direct emissions, but ARB staff mentioned in the March 27th LCFS workshop that they saw the need to "provide a path forward" on the indirect emissions side as well. Staff indicated that they would create a process for stakeholders to get credit (in the form of a reduced carbon intensity value) for demonstrated reductions in indirect emissions, perhaps through an expanded Method 2B. (SEMPRA1)

Response: The regulation as approved with modifications specifies the use of GTAP or an equivalent method to model the carbon intensity contributions from indirect land use effects. Section 95486(c)(3) and (d)(5). To evaluate ongoing developments in this field, the Board in Resolution 09-31 directs the staff to convene an expert workgroup to assist the Board in refining the approach that is used to model indirect emissions.

C-67. Comment: Models, inputs, and assumptions: the LCFS is heavily dependent on complex models with many inputs and assumptions. While indirect land use change is the most controversial area, there are additional factors that have not

been thoroughly verified. We recommend that ARB continue working to refine and improve upon the underlying pathway analysis at the heart of the LCFS through an ongoing public process. The goal should be to make sure the latest, best science is employed and to validate the models and results as data become available. (CALSTART)

Response: See response to Comments C-65 and C-66.

C-68. Comment: As CARB staff has repeatedly pointed out, there are many feedstocks with zero indirect land use impacts. We believe the industry would benefit from an early CARB signal and commitment to treat such feedstocks as zero for ILUC. This can be done by adopting a list of feedstocks that have zero or near-zero ILUC that includes but is not limited to those biofuels that:

- a. Derive from municipal or agricultural waste.
- b. Do not require arable land.
- c. Derive from crops grown on marginal agricultural lands or otherwise fallow farmlands, such as rotational and/or cover crops that are grown contra-seasonally to the primary crop. (EE1)

Response: In Resolution 09-31, the Board directed staff to develop criteria and a list of specific biofuel feedstocks that are expected to have no or inherently negligible land use effects on carbon intensity and to propose amendments, if appropriate, to the regulation resulting from this analysis by December 2009.

C-69. Comment: Changing the biomass to transportation fuel conversion technology resulted in a four percent increase in energy yield per acre. In the energy industry a four percent improvement in efficiency is huge. But, it is made almost negligible when it is compared to the preliminary theoretical ILUC carbon release. (UIC2)

Response: As noted in response to Comment C-68, in Resolution 09-31 the Board directed the staff to form an expert workgroup to evaluate land-use change issues such as the one raised by the commenter.

C-70. Comment: ILUC factor needs to be adjusted to reflect higher energy yields per acre of crop land. (A204NESTE1)

Response: Analysis of higher energy yields falls within the scope of the work to be conducted by the expert workgroup described in Resolution 09-31. See response to Comments C-66 through C-69.

C-71. Comment: Section 95486(d)(5) states that the Executive Officer must conduct analysis using GTAP. It is not clear in which phase of the application this should take place (before the application is complete, or during the Executive Officer review period). Greater clarity is needed, and CARB should place some

timeframe around this significant requirement. (EIN2)

Response: From a practicality standpoint, the GTAP analysis would most likely occur while the application is being reviewed by the Executive Officer after the application has been deemed complete. This is because the completeness determination must be made within 15 workdays after receipt of the application. Section 95486(f)(3). Thus, we expect that a complete application would include a request for the Executive Officer to conduct the necessary GTAP modeling. The Executive Officer and ARB staff would then perform the GTAP analysis after the application has been deemed complete.

After completion of the GTAP analysis, the Executive Officer would then publish the application and the results of the GTAP analysis for public review and comment as provided in section 95486(f)(4). Final action on the application would take place within the timeframe set forth in section 95486(f)(5).

C-72. Comment: On page IV-29, under “Adjustment of GTAP Model Results,” the CARB staff proposes that the main adjustment required in adapting GTAP to the present year (2008) is simply to adjust the corn yield. Two smaller questions arise:

- a. Why is the US aggregate average corn yield of 138.2 bushel per acre in 2001 used instead of the mid-western cornbelt average (12 main cornbelt states) of 139.9? and
- b. Why are the three recent years of 2006, 2007, and 2008 averaged in the proposal looking ahead to 2011-2020, as opposed to extending the corn yield trend, even the well-established trend of 1973-2004?

For the three years 2006-2008, the cornbelt average yield would be 154.8 bushels per acre, instead of the US aggregate 151.3 cited by CARB staff. The average of the 1973-2004 yield trend for the cornbelt states during the period 2011-2020 would be 167.5. The CARB staff should consider a dynamic approach to forward regulations, not a static approach. (PRX)

Response: The analysis in the ISOR uses aggregate average corn yield to reflect a nationwide average yield. Ethanol will be produced from corn originating from all parts of the country, not just the Midwest. Moreover, the analysis uses current average yields in order to reflect current real-world conditions. Future projections can often vary greatly and end up being inaccurate. During the implementation of the regulation, the staff intends to monitor real-world corn yields and make any needed changes to the regulation to reflect changes in corn yields. Also, this will be reviewed as part of the mandated reviews by 2012 and 2015. See also the response to Comments C-65 and C-66.

C-73. Comment: The heated debate over Indirect Land Use Change (ILUC) impacts and ILUC inclusion in lifecycle analysis should not result in a delay in the implementation of LCFS. With that said, the level of uncertainty, even in direction, of ILUC calculations are [sic] high. As such, the ability to propose new

and modified fuel pathways that include changes to emissions associated with ILUC is critical. It as noted at the March 27th meeting by CARB staff that an expanded Method 2B could provide a process by which ILUC modifications might be considered. (PRIMAFUEL)

Response: The Method 2A and 2B provisions in section 95486(c) and (d) provide an efficient process for incorporating new or modified pathways into the regulation and will incentivize the development and adoption of best practices and technologies. The regulated as approved with modifications provides for the Executive Officer to conduct the land-use change analysis using GTAP as part of a Method 2A or 2B application. This is because of the complexity and need for consistency and transparency in conducting these GTAP analyses. Indirect land use effects are highly uncertain, variable, and global in nature. Estimating such indirect effects requires the use of a robust model such as the GTAP model, which is capable of modeling the global effect of increased fuel demand on crop growth and land use.

With that said, the GTAP mode is available to regulated parties and applicants to use in estimating for their purposes the indirect land-use change effects. This will provide a cross-check on the ARB analysis in a Method 2A/2B analysis and will help ensure the evaluation is as complete and accurate as possible.

As noted previously, in Resolution 09-31 the Board directed staff to convene an expert workgroup to assist the Board in refining the approach that is used to model indirect emissions. In this way, the ARB will continue to ensure that the indirect land use change effects of the LCFS reflects the most up-to-date and science and understanding.

C-74. Comment: If the biofuels industry and California are to be ready to comply with the LCFS we need an accepted methodology to estimate ILUC values for alternative crops for which there is no GTAP data. A reasonable methodology would assume that if an acre produces more energy, it should have a lower ILUC value. (A2O4NESTE2)

Response: As noted in response to Comment C-29, in Resolution 09-31 the Board directed staff to convene an expert workgroup to assist the Board in refining the approach that is used to model indirect emissions. Evaluating ILUC values for alternative crops for which there are no GTAP data would fall within the scope of the expert workgroup's assessment. The results of the working group's assessment are to be presented to the Board by December 2010.

C-75. Comment: We should also reward credits for minimization of land use change impact to the early adopters, the environmental leaders who changed seed technology and/or land management practices to minimize both direct and indirect land use change impact because it was the right thing to do before the regulation was enacted. They should receive ILUC credits for the improvements they have made when they file a Method 2B pathway. Awarding those credits

should be based upon the responses to three simple questions: 1. What was the yield? 2. What is the yield? 3. What did you do to increase the yield? (A2O4NESTE2)

Response: Whether a regulated party receives “credit” for the actions noted above depends on the results of the Executive Officer’s GTAP analysis for that party’s particular Method 2A/2B application. We assume the commenter is referring to “credits” as meaning a reduction in a fuel pathway’s indirect contribution to the overall lifecycle carbon intensity resulting from one or more of the actions noted. Because the Executive Officer’s analyses will be conducted on a case-by-case basis, the effects on carbon intensity, if any, due to the actions noted by the commenter may vary depending on the particulars of each application. As such, it is impossible to predict with certainty whether any of the actions noted by the commenter would result in a “credit.” See also the responses to Comments C-72 through C-74.

C-76. Comment: Mitigation of ILUC impacts is consistent with long-standing precedent established in the California Environmental Quality Act (CEQA) that allows mitigation in some reasonable way. Minimization of ILUC impact is what we all want. Biofuel producers who are already minimizing ILUC impact should be able to benefit from their good works by being granted lower ILUC factors under Method 2B. The ILUC section of the LCFS must include language that provides “direct crediting” for the specific characteristics of fuels with feedstock production methods that already are inherently low carbon emitters. (A2O4NESTE)

Response: See response to Comment C-75.

C-77. Comment: Some of the early publishers on ILUC assumed constant crop yields which tend to overstate carbon debt. If one assumes historical trends of increasing yields the carbon debt is much less. (A2O4NESTE)

Response: In Resolution 09-31, the Board made the following findings:

1. staff performed complete lifecycle analyses and assigned scientifically defensible carbon intensity values to the fuels as detailed in the ISOR;
2. indirect land use change was appropriately included as part of the lifecycle analysis conducted by staff; and
3. to the extent the indirect land use values for crop-based biofuels included in the approved regulation may be different from values that may be generated in the future based on more robust data and more advanced analytical tools, the approved values are more likely to be lower rather than higher compare to subsequently-generated values.

Based on these findings, one can infer that the Board concluded that the assumptions made with respect to crop yield are reasonable and appropriate. With that said, the staff is committed to updating this information as it becomes available and is verified, pursuant to directives from the Board in Resolution 09-31.

C-78. Comment: Of course once an ILUC value has been determined for a crop, it should be able to be further mitigated by increasing the crop per acre yield by using advanced seed and crop management practices. (A2O4NESTE)

Response: See response to Comments C-72 and C-74.

C-79. Comment: In order to meet AB 32 statutory provisions, ARB must exclude crop-based biofuels despite, in several instances, seeming to pick it as a fuel "winner." If the LCFS gives credits for the use of food crops derived from biofuels (agrofuels), the resulting competition between the fuel use of Californians and food needs around the world will undoubtedly create a disproportionate impact on low-income Californians. Meanwhile, 4,706,130 people in California were considered to be in poverty in 2004, while CA ranked as the 15th worst state for food insecurity. The conversion of farmland for crop fuel production will directly impact these millions of Californians already in poverty by increasing food prices. (CERA1)

Response: The Board addressed this by assigning indirect land use change emissions to biofuels. This should provide the incentive to not overproduce biofuels that could have an adverse effect on the amount of food crops available. In order to comply with the LCFS, fuel producers will have an incentive to produce those fuels which have the lowest carbon intensities, including emissions from indirect land use change effects.

It is important to emphasize that in Resolution 09-31, the Board made the finding that the approved regulation meets the criteria set forth in section 38562 of the Health and Safety Code. In adopting regulations pursuant to AB 32 (e.g., the LCFS), the Board is required under this statutory provision to ensure, among other things, that activities undertaken to comply with the regulations do not disproportionately impact low-income communities. Thus, the Board's finding does not support the commenter's claim that the "crediting" of agrofuels necessarily results in a disproportionate impact on low-income Californians.

C-80. Comment: We would urge CARB to allow the use of existing 2A and 2B programs for the establishment of new ILUC values. For feedstocks with existing certification programs that claim to have no ILUC as part of their certification, CARB should evaluate the program and consider a default pathway for these certified biofuels. For feedstocks with no certification program, CARB should work with the State's agriculture department to establish best practices associated with establishing ILUC values. (ABFA)

Response: Method 2A and 2B in section 95486(c) and (d), respectively, already requires the Executive Officer to conduct an indirect effects analysis using GTAP or an equivalent method for each Method 2A/2B application deemed complete. Thus, the regulation already contains a mechanism for establishing new ILUC values. Further, in Resolution 09-31 the Board directed staff to convene an expert workgroup to help refine

the indirect effects analysis; the Board also directed staff to develop criteria and a proposed list of alternative fuels that are expected to have no or negligible land use effects on carbon intensity. See also the response to Comments C-18, C-20, C-37, and C-68.

Miscellaneous Comments

C-81. Comment: Section 95420 definitions, some of which reference fuel specification standards, will be tough for small volume, waste-derived alternative fuel suppliers to meet. We understand the need and desire to have alternative fuels and additives comply with statewide transportation fuel standards such as ASTM 0975 or ASTM 04806 and be registered under Section 211 of the Clean Air Act (40 CFR Part 79). We think that a major hurdle faced by waste-derived alternative fuel producers will be complying with all of the requirements in the cited regulations to the letter. For example, 40 CFR Part 79 consists of over 90 pages of small type requirements for fuels and additives including testing requirements for registration in Subpart F [Testing Requirements for Registration]. These include subchronic toxicity studies with specific health effects testing, fertility assessments/teratology, in vivo micronucleus assays, in vivo sister chromatid exchange assays, neuropathology assessments, glial fibrillary acidic protein assays, and analysis for numerous compounds such as polycyclic aromatic hydrocarbons (PAHs), nitrated polycyclic aromatic hydrocarbons (NPAHs), poly-chlorinated dibenzodioxins and dibenzofurans (PCDO/PCFOs), among others. Small volume alternative fuel producers will have great difficulty complying with these requirements without agreements with the larger producers who have adequate testing facilities, laboratory equipment, overall expertise and funding to meet these registration requirements. Given that alternative fuels are currently estimated at only one percent of the total volume of petroleum-based fuels, smaller volume alternative fuel producers are at a significant disadvantage in negotiating such agreements with the big producers, despite the low carbon intensity of the additives. Staff should evaluate the practicality of small volume, alternative fuel producers complying with these requirements themselves as opposed to, preferably, CARB taking on the obligations on their behalf or in a partnership, to advance the penetration of these fuels into the marketplace should a small producer not be able to get the large transportation fuel suppliers to take on the task. (CSD)

Response: The registration requirements cited by the commenter are set forth in 40 CFR Part 79 and are imposed by the U.S. EPA pursuant to section 211 of the federal Clean Air Act. They are requirements that apply to all fuels introduced into commerce in the U.S. for use in on-road motor vehicles. As such, ARB is without authority to grant waivers to regulated parties or otherwise bypass the federal registration requirements, even for small volume producers. With that said, it should be noted that 40 CFR Part 79 does contain specific provisions applicable to small volume producers in recognition of some of the issues raised by the commenter.

C-82. Comment: CARB should allow a process for parties to present individual data to establish unique carbon intensities for specified fuel pathways.

CARB should recognize a process by which individual companies can present data and establish more accurate carbon intensity values compared to the default values. CARB should not limit the use of such a process to instances where there is a “substantial” difference between the default carbon intensity and the carbon intensity that would be established through such a process, since any reduction is an improvement that is in line with CARB’s goals. Consistent with this, companies should be allowed to submit data covering the whole or any portion of the lifecycle of any fuel to establish a more accurate carbon intensity value.

We understand that CARB may be concerned with the administrative burden of such an approach. Therefore, we recommend the following process, which should ensure the accuracy of data, and avoid imposing a significant burden on CARB. The process should be transparent, and rigorous. The following, consistent with US EPA’s regulations for establishing baselines under the reformulated gasoline regulations, is a suggested process:

- a. Obligated parties may petition regulators to assign a carbon intensity value using actual process- or facility-specific data in lieu of state specified default values.
- b. The petition should include a technical justification that includes a description of the feedstock(s), and the production process. The same carbon intensity calculation approach, including the same models, methodological choices, data sets and software tools that were used to calculate the default carbon intensities should be used to calculate opt-in carbon intensities. This requires that the tool should allow the user to (a) replace default values with his/her own actual values, and (b) add new feedstocks, processes, or fuels as required to specify an alternative fuel pathway.
- c. The petitions should be certified by an auditor that meets specific requirements (i.e. EPA guidelines under the RFG rule could be used as a guide).
- d. Such petitions should be accompanied by a letter signed by the responsible corporate officer of the company, or his/her designee, stating that the information contained in the petition is true to the best of his/her knowledge.
- e. Within 60 days of receipt of a petition, CARB should notify the petitioner of the petition’s approval or of any deficiencies in the petition.
- f. If at any time it is determined that the carbon intensity values are incorrect, CARB should notify the petitioner and provide an opportunity to correct the values.
- g. The approved carbon intensity value should not be considered confidential business information, although the specific data underlying the petition should qualify as confidential business information. (SHELL)

Response: Contrary to the commenter’s claim, the regulation as approved with

modifications provides for a specific rulemaking process that can be used to establish new or modified fuel pathways and carbon intensities. The mechanism for establishing these new or modified pathways is set forth in Method 2A and 2B in section 95486(c) and (d), respectively. The regulation was modified to require Method 2A and 2B applications to undergo a full and formal rulemaking process pursuant to the Administrative Procedure Act (Government Code section 11340 et seq.). This will ensure both transparency to the public and affected stakeholders.

With regard to the 5.0 g/MJ “substantiality” requirement in Method 2A (section 95486(e)(2)), the Board determined that this requirement is necessary. This requirement is needed, not only to reduce the administrative burden (as recognized by the commenter), but more importantly to encourage true innovations in fuel pathways that result in significant carbon-intensity reductions. In other words, the incentive is provided for regulated parties to use Method 2A if they can find ways to truly reduce their pathways’ carbon intensity by more than a *de minimis* increment.

With regard to confidentiality of an approved carbon intensity value, the regulation as adopted does not provide for carbon intensity values approved by ARB or the Executive Officer to be treated as confidential.

C-83. Comment: CARB should allow a process for parties to present individual data to establish unique carbon intensities for conventional gasoline and diesel fuel pathways.

Section 95425 would establish a process by which unique carbon intensity values can be established for fuels produced from non-conventional crude, and for alternative fuels. This process would not apply to conventional fuels made from conventional crudes. It is inequitable for CARB not to treat conventional fuels produced from conventional crudes the same as the other fuels.

CARB should recognize a process by which individual companies can petition to establish more accurate carbon intensity values compared to the default values for fuels derived from conventional crudes, non-conventional crudes, and for alternative fuels. CARB should not limit the use of such a process to instances where there is a 10 percent difference between the default carbon intensity and the carbon intensity that would be established through such a process, since any reduction is an improvement that is in line with CARB’s goals of reducing emissions. The 10 percent requirement results in absurd outcomes and should not be included in the final rule. For example, under this concept improving 5 percent of the fuel by 40 percent would meet the 10 percent requirement, while improving 40 percent of the fuel by 5 percent would not.

Companies should be allowed to submit data covering any portion of the lifecycle and CARB should not arbitrarily deem certain parameters, such as refinery efficiency, to be “invariant.” CARB should encourage improvements in refinery efficiency and should recognize such improvements. Excluding refinery

efficiency is inconsistent with CARB's policy goals for the low carbon fuel program. (SHELL)

Response: The commenter is referring to language contained in earlier drafts of the proposed regulation. Since then, the regulation was modified and no longer contains the language at issue. In the LCFS, the carbon intensity is fixed for both the production and refining steps for processing the crude. This is to prevent "shuffling" of crudes (i.e., switching to a crude that is easier to refine as way to comply; the avoided crude is refined elsewhere in the world, resulting in no net reduction in greenhouse gas emissions worldwide).

The rule approved by the Board no longer has a requirement that there be a 10 percent difference between the default carbon intensity and the carbon intensity established by another method. However, the regulation as approved with modifications does specify that, for a regulated party to use Method 2A, the modified pathway must be lower than the analogous pathway in the Lookup Table by five grams CO₂ per MJ or more. See the response to Comment C-82 for additional details.

With regard to refinery efficiency, this is an example of a parameter for which the value would not vary enough from refinery to refinery to justify allowing individual refiners to use their own refinery efficiency values for calculating the carbon intensities of the fuels they produce. The staff estimated that the change in overall carbon intensity of gasoline or diesel produced from conventional crude due to differences in refinery efficiency would be less than one gCO₂e/MJ. The administrative burdens of including a provision that would allow producers to use individual refinery efficiencies would be too great to justify such a small improvement in the estimated carbon intensity of the fuel produced. This is particularly important given that emissions from refining in California will be subject to control under other AB 32 provisions (e.g., the "cap-and-trade" program currently under development) to reduce greenhouse gas emissions from stationary sources.

C-84. Comment: Because the LCFS is structured as a performance-based regulation, fair determination of a fuel's lifecycle carbon intensity is critically important. Lifecycle analysis serves as the foundation of any performance-based, technology neutral regulation. As such, it is essential that all regulated fuels are evaluated using the same analytical boundaries. (ABENGOA)

Response: The regulation as approved applies the same carbon-intensity assessment tools (CA-GREET and the GTAP Model) to all similarly-situated fuels.

C-85. Comment: We applaud CARB's intent to provide additional pathways that distinguish between both lower carbon intensity fuels and higher carbon intensity fuels. Doing so will help ensure accurate accounting of emissions and establish a level playing field for all fuels. (SIERRACLB2)

Response: No further response is needed.

C-86. Comment: Carbon capture & storage technologies do not represent “real” and “permanent” emissions reductions and may disproportionately impact low-income or traditionally overburdened communities. We oppose all CCS technologies as wasted investments that physically threaten surrounding communities. The proposed LCFS may incentivize (i.e. “pick a winner”) the CCS technology that has not been proven to even work. The ISOR states: “Large stationary sources of carbon dioxide, such as refineries and power plants are most viable candidates for CCS. Gasoline and diesel produced from such refineries could receive lower lifecycle carbon intensity values under the LCFS. “Staff is proposing that any regulated party, using a high carbon-intensity crude oil (> 15 gCO₂e/megajoule) brought into California that is not already part of the California baseline crude mix, would have to report and use the actual carbon intensity for that crude oil unless the party demonstrates that it has reduced the crude oil’s carbon intensity below 15 g CO₂e/megajoule using carbon-capture-and sequestration (CCS) or other method. We greatly oppose the inclusion of any CCS technologies in the LCFS, whether related to the transportation sector or not. Oil produced using CCS technologies will not have a lower net GWI than conventional crude oil when nobody has yet to prove that the carbon can remain permanently sequestered, and projects could impose other environmental harms including threatening groundwater quality and supply. (CERA1)

Response: In Resolution 09-31, the Board found that the GHG emission reductions resulting from the implementation of the approved regulation are expected to be real, permanent, quantifiable, verifiable and enforceable by ARB, and the regulation complements and does not interfere with other air quality efforts. More specifically, as noted in response to Comment C-79, the Board made the finding in Resolution 09-31 that the approved regulation meets the criteria set forth in section 38562 of the Health and Safety Code (HSC).

In adopting regulations pursuant to AB 32 (e.g., the LCFS), the Board is required under HSC section 38562 to ensure, among other things, that activities undertaken to comply with the regulations do not disproportionately impact low-income communities. The originally proposed regulatory text that was approved by the Board at the April 2009 hearing allowed for the use of CCS in cases involving high carbon-intensity crude oil under the specified circumstances (see former section 95486(b)(2)(A)2.c. in Appendix A of the ISOR). That CCS provision was incorporated essentially verbatim* into the regulation as approved (see approved section 95486(b)(2)(A)2.a.ii.III). Thus, the Board made the specific finding that the LCFS regulation and activities undertaken to comply with it (including but not limited to the use of CCS) do not result in a disproportionate impact on low-income Californians or low-income communities in California.

C-87. Comment: However, because “California Low CI Ethanol,” “Sugarcane Ethanol

* The only difference in verbiage between the original language and the language as approved was that “Lookup Table” in the original language was changed for clarity to “Carbon Intensity Lookup Table” in the approved language.

(Brazil)," "Biodiesel-Soybeans," and "Biodiesel or Renewable Diesel," all have proposed values less than the 2020 carbon intensity baseline for gasoline, they become the default "winners" long-term as well because they will have been already established and want to avoid future possible prohibitions, such as enforceable sustainability criteria ARB staff alleges they will develop in two years. Because corn is the overwhelming biofuel feedstock used in the U.S., one fuel provider commented at the March 27, 2009, workshop that the LCFS is just looking like a corn mandate. Because "Midwestern Average Corn Ethanol" was assigned a value greater-than the baseline gasoline, the proposed "default Lookup Table" will lead to the direct incentivization of siting biorefineries in California. (CERA1)

Response: One of the purposes of the LCFS is to incentivize the use of fuels that have lower carbon intensity. Fuels and fuel pathways that have carbon intensities low enough to meet the requirements of the regulation are, by definition, winners, and are the fuels that ARB seeks to incentivize. The LCFS is not a corn mandate, and the regulation does not incentivize the siting of biorefineries in California. As a result of the indirect land use change emissions from corn ethanol, corn ethanol may not have a carbon intensity value low enough to make a large contribution toward compliance.

C-88. Comment: In such instances, fuel processes that use CCS technologies cannot be considered a low-carbon fuel under any circumstances when the carbon can eventually escape. Even very low leakage rates through cracks or fissures in the ground and oil wells could reverse any purported climate benefits achieved by CO₂ burial. By factoring in theoretical and unproven CCS reductions in a given fuel's GWI value the ARB would not reflect actual emissions reductions, and would in effect allow-in dirtier crudes that could in turn lead to increased toxic and criteria pollutant emissions. To address this potential backsliding dynamic, we recommend that 1) ARB thoroughly analyze the full lifecycle for each individual grade of feedstock including all dirtier crudes, incorporating all processing stages such as extraction and refining, 2) The LCFS be an entity-specific regulation so that dirtier fuels cannot hide behind averaged default values, and 3) the LCFS should not give any credit for use of CCS technologies. The explicit reference to CCS in the proposed regulatory language would raise a very real and substantial threat to all communities surrounding sites of sequestration and storage, and encourage investments needed elsewhere in questionable technologies. A large leak of CO₂ could kill vegetation, animals, and humans over a fairly large area. Fuel providers could target EJ communities in California that have large oil-well fields, such as in Bakersfield, Wilmington, and other areas vulnerable to natural disasters like earthquakes. Thus, the potential siting of CCS projects in traditionally overburdened communities could also violate AB 32's statutory mandate to not disproportionately impact traditionally overburdened communities. (CERA1)

Response: The LCFS regulation is explicit on how high-carbon intensity crudes are to be treated. Section 95486(b)(2)(A)2 addresses the carbon intensity of fuels produced

from high carbon-intensity crude oil. In California, the siting of carbon capture-and-sequestration (CCS) facilities will be subject to the California Environmental Quality Act (CEQA) and land use permits, among other requirements. These programs and requirements are designed to address the types of issues identified by the commenter. Also, the LCFS regulation specifies that only CCS technologies that have been demonstrated to reduce the carbon intensity to 15.00 g/MJ or less, as determined by the Executive Office, will be permitted under section 95486(b)(2)(A)2.

The LCFS regulation only recognizes the use of carbon capture-and-storage technologies that have been proven to generate real and permanent emissions reductions. Because of this, the staff is confident that the permanence and validity of emission reductions from carbon capture and storage technologies can be determined with a sufficient degree of confidence.

With regard to the use of CCS as potentially impacting low-income California communities disproportionately, this was addressed in response to Comment C-86.

C-89. Comment: Although the ARB staff purport to not be "picking fuel winners and losers" the ISOR recognizes that the "carbon intensity values represent the currency" in which the LCFS credit trading program is based. As such, the "default Lookup Table" will help guide or strand investment decisions towards certain fuels as it is sporadically updated with new or modified values at the Executive Officer's (new & novel) discretion that the proposed regulation seeks to grant him. In recognition of this dynamic, ARB's proposed "default Lookup Table" incentivizes corn-based ethanol well beyond the first 3-5 years of the LCFS that the ARB expects it to be the "vast majority of ethanol used." The proposed default value for the proposed new pathway "California Low CI Ethanol" is below the comparable baseline for gasoline with a 10 percent reduction required in 2020. In effect, an entity could meet the LCFS using this new "best practices" corn blend up until the expired term of the regulation, and the regulation would not force any significant innovation to truly low or zero-carbon sources because no advanced biofuel pathways are proposed for approval at this time and may not be proposed until they become commercially viable. In the near-term the absence of appropriate vehicle, fuel transport, or distribution systems for electricity or other truly low-carbon alternatives will incentivize the food-crop biofuel options. (CERA1)

Response: As noted previously, one of the primary purposes of the LCFS is to incentivize the use of fuels that have lower carbon intensity. Fuels and fuel pathways that have carbon intensities low enough to meet the requirements of the regulation are the fuels that ARB seeks to incentivize. The carbon intensity of "California Low-CI Ethanol" is not low enough without large volumes being used for it to play a significant role in compliance with the 2020 requirement of 10 percent reduction. Fuels having carbon intensities from 50 to 80 percent less than gasoline are expected to be needed to meet the 10 percent reduction requirement. Only fuels made from renewable blendstocks such as cellulosic ethanol or wastes at this time have carbon intensities this

low. These are examples of the fuels that will be incentivized by the LCFS over the long term.

C-90. Comment: The technological improvements I outlined above were made possible by a government that recognized the significant benefits of ethanol for our environment, national security and economy. They set the goal, we met it and then surpassed it. We would still be in the age of inefficient, farm-scale ethanol plants if not for the visionaries at every level of government who prompted efficiencies. The only way to continue these breakthroughs to develop the ethanol of tomorrow is to maintain a strong ethanol industry today and entice it to grow even further. POET is not requesting special preference for our products. We are simply requesting the level playing field promised as part of the LCFS and that CARB hold ethanol to the same carbon accounting standard as petroleum, hydrogen, electricity, and all other fuels. The ethanol industry has made tremendous strides in not only helping our environment, but reducing our reliance on foreign oil and helping our nation's economy. CARB should refrain from derailing those benefits with a well-intentioned but significantly flawed policy. (POET1)

Response: The ARB believes that the LCFS regulation treats all fuels (biofuels and petroleum fuels) fairly and equitably and that all fuels are held to the same carbon accounting standard. The carbon intensity values of all fuels are based on the same models and the best available scientific understanding of the fundamental processes that contribute greenhouse gas emissions.

With regard to the indirect effects on carbon intensity from land use changes, it is important to note that in Resolution 09-31 the Board found:

1. The staff performed the complete lifecycle analysis of several fuels, including petroleum-based fuels, biofuels, and other non-liquid alternatives and assigned the scientifically defensible carbon-intensity values to these fuels as detailed in the ISOR (at IV-1 through IV-51);
2. Indirect land use change was appropriately included as part of the lifecycle analysis conducted by staff; indirect land use change is not inconsequential to the lifecycle of some crop-based biofuels; and to exclude indirect land use effects in the initial LCFS regulation would allow fuels with carbon intensities that are similar to gasoline and diesel fuel to function as low-carbon fuels – delaying the development of truly low-carbon fuels and jeopardizing the achievement of a 10 percent reduction in carbon intensity by 2020;
3. To the extent the indirect land use values for crop-based biofuels included in the approved regulation may be different from values that may be generated in the future based on more robust data and more advanced analytical tools, the approved values are more likely to be lower rather than higher compared to subsequently-generated values;

4. No other significant indirect effects that result in large GHG emissions have been identified that would substantially affect the LCFS framework for reducing the carbon intensity of transportation fuels;
5. The regulation approved by the Board was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective GHG emission reductions from transportation fuel used in California; and
6. None of the four scientific peer reviews of the LCFS prepared pursuant to section 57004 of the Health and Safety Code requires major modifications to either the regulation or the analysis used to support the regulation.

From these findings, it is clear that the LCFS regulation provides a level playing field for reducing the carbon intensity of the various fuels subject to the regulation. With that said, the Board recognizes that the science of land-use change analysis continues to evolve, and the regulation may need to be updated in the future to reflect such developments. Therefore, pursuant to Resolution 09-31, the staff will continue to work with stakeholders to evaluate other models and approaches that could be used to assess indirect land use change effects. To this end, the Board directed the staff to establish an expert workgroup to evaluate the approaches for estimating the indirect land use effects and to assist the Board in further refining such land use change analyses.

C-91. Comment: For the cellulosic ethanol pathway, the energy inputs for biocatalyst (enzymes) production should be included. These enzymes can not be regenerated post fermentation processes, and need to be constantly replenished. (CONOCO)

Response: A pathway for cellulosic ethanol was not completed in time for inclusion in the regulation. Staff is still investigating the feasibility of incorporating such a pathway into the regulation in a future rulemaking. Having said that, it should be noted that CA-GREET already accounts for the energy in enzyme use.

C-92. Comment: For both the soy biodiesel and renewable diesel pathways, the default carbon intensity values for soy oil production (soybean farming, transport and oil extraction) appear to be different. These values should be the same as they represent the same soy oil feedstock. (CONOCO)

Response: As noted previously at the beginning of this FSOR, it is ARB's intent to incorporate fuel pathways and carbon intensity values for biodiesel and renewable diesel derived from Midwest soybeans before the end of this rulemaking. Comments on those pathways will be addressed in a separate FSOR.

C-93. Comment: For both the soy biodiesel and renewable diesel pathways, the

energy use in soy oil extraction, 4,309 BTU/lb oil extracted was nearly half of the value reported in the 1998 NREL Urban Bus study (8008 BTU/lb of oil extracted. This number needs to be verified and the proper reference needs to be supplied. (CONOCO)

Response: See response to Comment C-92.

C-94. Comment: The allocation of energy use and emissions to soybean meal co-product in soy biodiesel and renewable diesel pathways seems problematic and needs to be resolved. This inconsistency in co-product allocation has caused a significant impact on the carbon intensity values for soy biodiesel and renewable diesel. For example, more than half of the energy use in soy oil transesterification process, 167,986 BTU/MMBTU (46 percent of total energy use in the entire LCA), was assigned to soybean meal, which is not a co-product of this step. This problem was due to the mixed use of two sets of allocation fractions, subsystem-based and whole-system-based allocations at various LCA steps. The sub-system allocation fractions were applied in the soybean farming step; while the whole-system allocation fractions were used in the soy oil extraction and transesterification (hydrogenation for renewable diesel) steps. As a result, energy use and emissions were allocated to soybean meal twice in the LCA – one for soy oil extraction and the other for transesterification. This allocation methodology is incorrect by the LCA principles. Soybean meal is not a co-product of the transesterification process and should not claim any co-product credit in this step. (CONOCO)

Response: See response to Comment C-92.

C-95. Comment: Other data appear to be obtained from a single resource or personal communications. In this case, sensitivity analysis may be useful to demonstrate the impact of critical parameters, such as the types of feedstock, the preprocessing requirements, the technologies available for generating LFG, the separation and compression efficiencies for natural gas, the flue gas treatment, etc. (CONOCO)

Response: The staff has performed a sensitivity analysis to evaluate the effects of key parameters. The results of the sensitivity analysis are presented in Appendix C to the Staff Report.

C-96. Comment: Also relevant to this testimony is an effort we are undertaking to introduce the concept of a “feebate” for fuel. We have attached a summary of a piece of legislation being suggested for introduction in conjunction with low carbon fuel rule implementation to California regulators and at a national level in either the 2009 energy bill or as separate legislation in 2010. The idea is to impose a 4 cent per gallon “fee” on fuels and then use 100 percent of the funds to set up a “low carbon permanent fund” to provide a “rebate” for fuels that reduce greenhouse gas emissions through use of low life cycle carbon biofuels

and/or fuel efficiency additives. We mention this initiative only because its implementation in parallel with the low carbon fuel regulations will require some reconsideration of how you evaluate alternative fuels and measure carbon emissions (through evaluation of the fuel life cycle carbon emissions or going out through evaluation of carbon emissions at the tailpipe). (CO2STAR)

Response: This suggestion would require legislation before it could be implemented and is therefore outside the scope of the 45-day notice. No further response is required.

C-97. Comment: We have been discussing first in Europe and UK and more recently in California a very important difference in the approach of calculating carbon emissions and control strategies for trading between industries affected by carbon cap and trade programs and the calculation of carbon emissions from petroleum. All other industries in the EU that are affected by cap & trade programs must first undergo an analysis of energy use for their production process and allocate this energy use to each product and by-product. (CO2STAR)

Response: The Board has not yet adopted a cap-and-trade program in California. A cap-and-trade provision in the LCFS can be considered once the Board adopts a cap-and-trade regulation. Indeed, the approved regulation already has a placeholder (section 95488) that is intended to specify regulatory provisions, if needed, for interfacing the LCFS with the cap-and-trade regulation currently under development.

C-98. Comment: It is thus critical that all major emissions sectors (transportation, electric power, industry, agriculture/forestry) are to be approached using the same methodology, or the comparison between petroleum emissions and any alternative fuel will greatly understate the emission benefits of these alternative fuels. Furthermore, if other measures are included in further iterations of the rule (fuel additives for example), the carbon benefits between the primary fuels used (gasoline, diesel, jet fuel) and biofuels or these measures will be underestimated. (CO2STAR)

Response: The LCFS governs only the carbon intensity of transportation fuels produced in or imported into California. To the extent the comment applies to emission sectors beyond transportation fuels or to fuel additives, the comment is beyond the scope of the 45-day notice and the LCFS program. Therefore, no further response is required. We note that we will continue to use the best tools and methodologies available for estimating emissions and performing the carbon accounting needed to ensure that the LCFS achieves the target reductions in greenhouse gases.

C-99. Comment: We also mention this example because the implementation of this plan by the State of Maranhao and small producers in Brazil would result in a large amount of oil and food that could provide a clear feedstock pathway for sustainable biofuel production. Planting of Macauba trees on 1 million hectares

of state land and additional small producer land would result in 4 million+ metric tons of vegetable oil (4 percent of current global vegetable oil supply), 8 million+ metric tons of biomass for conversion to energy or fuel and millions of metric tons of food for local or export markets. This is a large volume of oil production that is new, with very high carbon benefits that require consideration in development of flexible models and policy options. (CO2STAR)

Response: See response to Comment C-50.

C-100. Comment: In addition, they must also undergo an “economic weighing” that allocates carbon emissions to each product on the basis of its economic importance in the production process. This is to avoid the problem of two products like road gravel and gold that come from the same mining process having the carbon energy value assigned based on energy use when in fact the mining is being done to extract gold. This same principal should apply to petroleum and the ISO Scientific Committee that was responsible for carbon life cycle rules for petroleum made this suggestion to the ISO committee. However, because it is a “consensus” process, the petroleum industry protested and the proposal was never advanced. However, if CARB goes through with implementation of a cap and trade program, it will immediately have to face the same question. Should there be “economic weighing” in California “cap and trade” programs? If so, can this be justified if it is also not done to the petroleum sector. Petroleum emissions from transportation represent about 40.7 percent of California’s greenhouse gas emission, almost double the other two major carbon emissions (electric power 22.5 percent and industry 20.5 percent). How can CARB require economic weighing in cap and trade in these sectors and not do the same with petroleum fuels. (COSTAR)

Response: This comment applies to California’s cap-and-trade program currently under development. Because the LCFS regulation’s only interface with the upcoming cap-and-trade is a placeholder in section 95488 (see response to Comment C-97), the substantive aspects of this comment are outside the scope of the 45-day notice. Therefore, no further response is required.

C-101. Comment: We appreciate the proposed rule's provision in Section 95486(1)(2)(B) providing that, if a 2A or 2B application is approved by the Executive Officer, the carbon intensity values, associated parameters, and other fuel pathway-related information obtained or derived from the application will be incorporated into the Method I Lookup Table without restriction. This not only makes it possible for others to use the customized inputs or pathway, but allows the public to understand the basis for the new carbon intensity values. (FOTE2)

Response: Section 95486(f)(4) was modified so that information from an approved Method 2A or 2B application would be released in accordance with the Public Records Act (Government Code section 6250 et seq.) and ARB’s implementing regulations (17

CCR sections 91000-91022).

C-102. Comment: Due to these enormous risks, NRDC strongly supports CARB's intent to provide additional pathways that distinguish between both lower carbon intensity fuels and higher carbon intensity fuels. Doing so will help ensure accurate accounting of emissions and establish a level playing field for all fuels. CARB must continue its efforts to address high-carbon intensity fuels by including provisions to differentiate these fuels, including the addition of land use change values associated with the production of these fuels. Doing so will allow for more accurate assessments to be made and the correct market signals to be placed on both low and high-carbon intensity fuels. (NRDC3)

Response: No further response is required.

C-103. Comment: While the proposed regulation currently does not list a municipal solid waste to fuels pathway, we encourage the ARB to begin working with Fulcrum and other leading developers to develop such a pathway under Methods 2A and 2B of the regulation. It is important that ARB begin working on the development of this pathway so that the market will clearly recognize that biofuels from waste produce -- from waste products can make a significant contribution to the Low Carbon Fuel Standard. (SEMPRA2)

Response: During the implementation of the regulation the ARB will investigate the feasibility and necessity for developing a municipal solid waste to fuels pathway. The Method 2B provisions of Section 95486 will allow the establishment of carbon intensity values for this pathway. See also responses to Comments C-1 through C-6, and C-9.

C-104. Comment: We do have a couple of concerns about the treatment of waste in the LCFS. Our first concern is that there has been no pathway added for dedicated anaerobic digesters. We see anaerobic digesters as a key for moving forward with diversion of organic materials in California and moving forward. We understand that the staff has limited resources. But the sector is a fledgling sector, especially in the waste side. And it really doesn't have the resources to develop the pathway by itself. We are encouraged to hear the staff say that they're interested in moving along and developing this pathway for dedicated digesters. We would just encourage you to ask staff to prioritize this and expedite the process and really move this pathway to the very top of the list. (CAW)

Response: See response to Comment C-103.

Comments on Administrative Facets of the LCFS

C-105. Comment: (Section 95426, Page 38): ADM recommends defining which Level (I, II, III, or IV) in the carbon intensity look-up table the 10 percent reduction is determined from in the "10-10" Substantiality Requirement.

CARB states, "Method 2A yields an overall blendstock carbon intensity that is lower than the value calculated using Method 1 by more than 10 percent..." in the "10-10" Substantiality Requirement. ADM believes it is appropriate for this determination to be based on the Level 2 values and recommends this be made explicitly in the regulation. (ADM)

Response: The first part of the comment dealing with "Level I, II, III, or IV" pertains to an earlier version of the rule released before the formal rulemaking began and is no longer relevant. Those terms are not used in the approved regulation. With regard to the former "10 percent" substantiality requirement, the regulation was modified in section 95486(e)(2)(A) to replace the relative 10 percent reduction requirement with an absolute reduction requirement (i.e., the reduction in carbon intensity must be at least 5.00 grams CO₂-eq/MJ).

C-106. Comment: (Section 95426, Page 37): CARB states that "Input variables that are identified as invariant input parameters in GREET may not be modified..." in Method 2A, Paragraph A, but does not detail what is considered an invariant or variant variable. Additionally, the Detailed California-Modified GREET Pathway for Denatured Corn Ethanol - Version 1 nor the Supporting Documentation for the Draft Regulation for the California Low Carbon Fuel Standard specifically identify which input variables are considered invariant.

ADM supports CARB's customized lookup table method to account for the significant differences that can exist between plants and which encourages innovation and improvement in the industry. ADM recommends that the table in Appendix B of the Denatured Corn Ethanol Pathway document be modified to include a column identifying which input values are considered variant variables. At a minimum ADM suggests that the values under the headings of Co-Product Credit, EtOH Production (specifically EtOH yield, energy use, fuel mix, and purchased electricity) and EtOH T & D be considered variant variables and as such subject to modification in Method 2A. ADM believes that all these values can be collected with relative ease and they are verifiable on a facility specific basis. (ADM)

Response: The comment about "invariant variables" pertains to an earlier version of the rule released before the formal rulemaking began and is no longer relevant. That term is not used in the approved regulation. The regulation as approved specifies that a proposed Method 2A application must use only inputs that are already incorporated in CA-GREET and cannot add any new inputs (e.g., refinery efficiency). See section 95486(c)(2).

C-107. Comment: As noted above, Shell believes that under the LCFS, obligated parties should be allowed to submit data demonstrating that any emission reductions made under AB 32 resulted in an improvement of the carbon intensity of the fuels produced, and that the obligated parties should be permitted to

petition for unique carbon intensity values for its fuels. (SHELL)

Response: As discussed in the Staff Report, the regulation disallows the use of GHG credits that are generated outside the LCFS program. ISOR at X-9, 10. This is to ensure that improvements in the LCFS fuel pool occur. However, staff will continue to evaluate the feasibility and effectiveness of allowing credits generated from marine and aviation transportation areas, which are currently not included in the LCFS fuel pool, to be used in the LCFS program. The ARB staff will provide an update on the potential use of GHG credits from lower-carbon marine and aviation fuels to be used in the LCFS program as part of the two program reviews required in section 95489.

C-108. Comment: CARB staff has conducted very diligent pathway analysis for 13 individual compliance pathways. While these studies are very well documented, no single pathway has been subjected to independent and complete validation of all the parametric data incorporated in these studies. While such full pathway validation is resource intensive, the credibility of the pathway analyses is crucial to the sustained success of the LCFS. AQMD staff recommend that detailed audits and validation studies of the most likely near term pathways be initiated as soon as possible, so the results of such audits are available for review as part of the first periodic program review. (SCAQMD1)

Response: The pathway supporting documents were made available prior to being incorporated into the regulation, and their validity has already been subject to extensive public review and comment. As the LCFS regulation is implemented, critical aspects of the regulation will be subject to the ongoing review by the Executive Officer pursuant to the required programs reviews set forth in section 95489 and Board's directives in Resolution 09-31. A review of the parametric data contained in the fuel pathway supporting documents can be part of these follow-up activities, if such a review is deemed necessary by the Executive Officer.

C-109. Comment: Under Method 2A of the regulation, the LCFS allows for the substitution of data other than the default values to be provided by CARB in the Carbon Intensity Lookup Table. (The values for the Lookup Table have not been published as of April 8, 2009). It is assumed that the basis of this set of default values will be the 13 separate pathway assessments issued by CARB. Under the CARB proposal, substitution of a default value is only allowed in which a 20 percent change in well to tank GHG carbon intensity is achieved (i.e., 5 grams or greater well-to-tank (WTT) impact per MJ out of a total gasoline WTT value of 24.2). In addition, default value substitution is only allowed on fuel volumes which exceed a minimum of 10 million gasoline gallon equivalents (gge) annually. AQMD staff believes that both the 5 gram threshold (i.e., essentially 20 percent of the WTT value) and the 10 million gallon annual threshold are too restrictive, especially in the short term. Some alternative fuel pathways may not start out at such high volume. Also, reducing the WTT from a baseline of 24 grams down to at least 19 represents the equivalent to a 20 percent increase in upstream production efficiency. Only the largest regulated parties are likely to be

able to accomplish such large incremental upstream efficiency improvements. In contrast, even a 2-5 percent improvement would be meaningful, and result in real carbon intensity reductions, as well as mass GHG reductions. AQMD staff therefore recommends that under the Method 2A Sustainability Review, that improvements of greater than 1 to 2 percent be allowed, with minimum incremental volumes of 1 million gallons, for at least the first five years of the regulation. (SCAQMD1)

Response: The Board weighed the advantages of having lower threshold values for the carbon intensity and fuel volumes in order to be eligible under Method 2A against the administrative burden needed to implement and enforce the provisions of Method 2A. Moreover, the Board considered whether smaller threshold levels for carbon intensity would incentivize truly innovative reductions in carbon intensity. Based on these considerations, the Board concluded that the 5 gram and 10 million gallon annual threshold are reasonable and appropriate.

These requirements should not be overly burdensome for several reasons. First, the 10 million gallon requirement applies only if more than 10 million gallons per year are produced, in total, by all producers of that fuel. Second, new pathways are not subject to Method 2A, but rather they are subject to Method 2B. New pathways proposed under Method 2B are not subject to either the 5 gram reduction requirement or the 10 million gallon production requirement. Finally, pursuant to Resolution 09-31, the staff is developing guidelines for an informal process to allow an innovator with a new project to estimate the carbon intensity potential of a new process in the early stages of that project. This will let innovators know early in the process whether their proposed projects can meet the Method 2A or 2B requirements before they commit their full resources in the projects.

C-110. Comment: If CARB desires to control carbon intensity, it should require that regulated parties track the carbon properties of crucial gasoline building blocks such as hydrogen from which commercial fuels derive. (SCAQMD1)

Response: This requirement is already incorporated in the full, fuel lifecycle analysis that was conducted for gasoline and diesel. As with other aspects of the program, the lifecycle analysis will be subject to the two mandatory program reviews in section 95489.

C-111. Comment: In general, we urge CARB to model the LCFS approval procedures on the diesel verification procedure, which generally works well, and to carefully avoid the pitfalls that have plagued the multimedia process. (EIN2)

Response: The approval of fuels under the LCFS cannot be structured in the same manner as the diesel verification procedure. This is primarily because the diesel verification procedure relies on laboratory emissions tests of vehicles and the measurement of engine out emissions. By contrast, the LCFS is concerned with lifecycle “well-to-wheels” emissions of fuels, and not just the tank-to-wheels emissions

(i.e., tailpipe emissions). Thus, laboratory testing of tailpipe emissions will not provide the well-to-wheels carbon intensity values that are needed for the LCFS.

With respect to the “pitfalls” with the multimedia process, as we noted previously the regulation does not, by itself, establish motor vehicle fuel specifications that would trigger the multimedia evaluation requirements in HSC section 43830.8. See ISOR at V-26 through V-33. Thus, a new pathway or sub-pathway would not need to be accompanied with a multimedia evaluation if the fuel from that new pathway or subpathway otherwise meets other fuel specifications promulgated by ARB or the Division of Measurement Standards, whichever applies.

To help ensure that bottlenecks are not created because of Method 2A and 2B, in Resolution 09-31 the Board directed the staff to develop guidelines to assist applicants through the process. The Board also directed staff to monitor the implementation of the program. Moreover, the two program reviews in section 95489 require the Executive Officer to identify, among other things, hurdles or barriers to the efficient implementation of the regulation. From this monitoring effort and the program reviews, the Executive Officer is directed to propose amendments, if needed, in future rulemakings to address such identified hurdles or barriers.

Based on the reasons discussed above, the Method 2A and 2B provisions in section 95486 are not expected to create a bottleneck to the commercialization of promising new technologies.

C-112. Comment: The 30-day public review and the subsequent 45-day Executive Officer review in section 95486(f)(4) and (5) seem reasonable. However, CARB should specify what happens if the Executive Officer review raises an objection to a specific item, methodology or dataset in the application. As it stands, it is not clear if the process would have to return to the beginning, with a new public review and Executive Officer approval. We would urge CARB to specify that the process will not return to the beginning, but that the regulated party would have an opportunity to address the specific parts of the application that have been contested, and be assured that the remainder now had implicit approval. This is critical to avoid a potentially endless cycle of public and executive officer review, in which a new issue is raised as a barrier in each case. This endless review cycle has plagued the Multimedia analysis. (EIN2)

Response: The regulation was modified to make consideration of a Method 2A or 2B application essentially a formal rulemaking (by reference to the rulemaking provisions in the Administrative Procedure Act (APA), Gov. Code section 11340 et seq.). After the specified 15 workday Executive Officer review for completeness, an application deemed complete would be published for public comment with the requisite 45-day comment period set forth in the APA. At the end of that period, the Executive Officer would either take final action to approve or disapprove an application or would make changes to the application that would make it approvable. If those changes are substantive, the proposed changes would be subject to a supplemental comment period of at least 15

days.

We anticipate that if the Executive Officer identifies deficiencies in the application during the 15 workday application review period, the application will be returned to the applicant and the applicant will be given the opportunity to correct the deficiencies. After correcting the deficiencies, the applicant would be able to resubmit the application. If the Executive Officer disapproves the application at the end of 45-day comment period, the applicant would have to resubmit an application that addresses the reason for disapproval. The application, if resubmitted with the required changes, would then be made available for another formal public review and comment period. Alternatively, as noted above the Executive Officer may decide that changes can be made to the application to make it approvable; those changes, if substantive, would be made available for a supplemental comment period. At the end of a Method 2A or 2B “rulemaking” process, the Executive Officer would take final action to either to approve or disapprove the application. This decision may take place during a public hearing, as provided in Gov. Code sections 11346.5(a)(17) and 11346.8(a) and (b).

This process ensures transparency by giving the public a meaningful opportunity to comment on Method 2A or 2B applications that are submitted. At the same time, treating these applications to a formal rulemaking process, rather than the administrative process noted by the commenter, should help to expedite the process as much as feasible.

C-113. Comment: The regulation does not appear to specify what happens if the Executive Officer does not approve the proposed pathway. Will another carbon intensity number be assigned to that fuel from a similar, approved pathway, or will it be banned from sale in California until approved? (EIN2)

Response: If the Executive Officer does not approve the proposed new or modified pathway, the regulated party for that fuel may still be able to sell the fuel in California. Under those circumstances, the regulated party would need to comply with the LCFS requirements, but instead of using the unapproved pathway, the regulated party would use the carbon intensity value in the Lookup Table that most closely corresponds to the production process used to produce the regulated party’s fuel. Section 95486(b)(2)(B). If the regulated party’s fuel has no corresponding pathway in the Lookup Table, then that fuel would not meet the LCFS requirements.

C-114. Comment: Like the multimedia analysis, the approval of a new pathway may require input from agencies other than CARB (agriculture, forestry, etc), and experience shows that this input can be a lengthy and complicated process. In the proposed regulation, it is unclear how such input will be incorporated into the application process, and during which phase this would take place. We urge great care in managing the timeframes associated with the input of other agencies, and especially any external peer review processes. (EIN2)

Response: From the response to Comment C-112, it should be clear that the input

from interested stakeholders, including other agencies, on the proposed final action of a new or modified pathway would occur during the 45-day public comment period. The input received would be considered for purposes of determining whether the application complies with the scientific defensibility, burden of proof, substantiality, and other applicable requirements of the regulation. As the regulation is implemented, the Executive Officer will gain a better understanding of the timeframes needed to accomplish these objectives and will consider making appropriate changes if needed. It is important to note that the APA requirements for public review are minimum requirements; if needed, the Executive Officer can make the public review periods longer than the minimum required. See also response to Comment C-113.

C-115. Comment: The Board should direct staff to review the Executive Approval procedure under section 95486 to ensure an efficient and fair process that does not inadvertently hinder new fuel technology developments, and should direct Staff to return to the Board by December 2009 with recommended modifications to the regulation, as appropriate. (EIN2)

Response: See response to Comments C-112 through C-114. Like other aspects of the LCFS implementation, implementation of the approval process for Method 2A and 2B is subject to both the program reviews specified in section 95489 and to the directive in Resolution 09-31 for the Executive Officer to propose needed changes based on his/her ongoing monitoring of the program implementation. Because the program's implementation will not begin until after January 2010, the commenter's suggestion to bring recommended changes in December 2009 is a bit premature.

C-116. Comment: Several issues concerning enforcement have been discussed briefly by ARB but not resolved. For example, what level of accuracy will ARB need in order to enforce the LCFS standards, including the percent reduction in carbon intensity as it relates to all the various fuels that will be subject to the LCFS. (WSPA)

Response: Section 95484(c)(5) specifies rounding procedures and the number of significant figures for reporting values required by the regulation. There is no requirement in the approved regulation for regulated parties to report the "percent reduction in carbon intensity" in any form or for any fuel.

It should be noted that the program's first year (2010) is a reporting year only. This is to allow the identification of issues and to make regulatory or programmatic changes to address such issues before actual reductions in carbon intensity are required.

C-117. Comment: Studies with system boundaries that measure "well-to-wheel" GHG emissions can identify key contributing parameters within the biofuel supply chain. This approach can be used to develop appropriate guidelines to reduce GHG emissions. (VALENTE)

Response: This suggestion can be considered during the mandated 2012 and 2015

program reviews specified in section 95489 (i.e., this falls within “advances in full, fuel-lifecycle assessments” in section 95489(a)(3)).

C-118. Comment: Reduce the Carbon Intensity reduction goal percentage from 10 percent to 8 percent for small refiners. (KORC1)

Response: At the April 2009 hearing, the Board considered this request but did not approve it. The Board concluded that, at this time, there is no reason to have a different standard for small refiners. In summary, the Board determined that small and large refiners alike should be subject to the same 10 percent reduction compliance schedule in 2020.

C-119. Comment: Also, we oppose the proposal to allow the Executive Officer to amend and approve subsequent amendments to the default "Lookup Table" at will. "The proposed regulation establishes that the Executive Officer may approve subsequent amendments to the Lookup Table after a specified public process... Following a formal public review process as identified in the regulation, the Executive Officer may approve additional carbon intensity values to be added to the Lookup Table." The proposed regulatory language grants the Executive Officer the authority to "add to the Lookup Table any new carbon intensity values and their associated pathways, either at the Executive Officer's initiative or Executive Officer approval of a new fuel and pathway proposed by a regulated party pursuant to Method 2A or 2B." First, we note that there is no prior legal authority or precedent to grant the Executive Officer such unilateral regulatory authority. Second, we note the great magnitude of discretion that this new and novel proposal would grant to the Executive Officer. "A regulated party that proposes to use Method 2A or 2B bears the sole burden of demonstrating to the Executive Officer's satisfaction, that the proposed method is scientifically defensible. For each of its transportation fuels for which a regulated party is proposing to use Method 2A, the regulated party must demonstrate, to the Executive Officer's satisfaction, that the proposed Method 2A meets both of the substantiality requirements. To account for indirect effects, including land-use changes, regulated parties using Method 2A or 2B would need to petition the Executive Officer to conduct the appropriate modeling analysis as set forth in the LCFS regulation. The results of these analyses will be added to the applicable carbon intensity values in the Lookup Table. Alternately, the regulated party could use the standard Lookup Table value for CARBOB, gasoline, or diesel for fuel derived from non-high carbon intensity crude oil, but only if the regulated party can demonstrate to the Executive Officer that its crude production and transport carbon-intensity value has been reduced to a specified level and meets other specified criteria. To this end, staff is proposing that any regulated party, using a high carbon intensity crude oil (> 15 g CO₂e/megajoule) brought into California that is not already part of the California baseline crude mix, would have to report and use the actual carbon intensity for that crude oil unless the party demonstrates that it has reduced the crude oil's carbon intensity below 15 g CO₂e/megajoule using carbon-capture-and sequestration (CCS) or other method.

Upon this demonstration, the regulated party would be permitted to use the average carbon intensity value for the California baseline crude mix (i.e., crude oils currently used in California refineries. (CERA2)

Response: State law permits the Board to delegate to the Executive Officer any power, duty, purpose, function or jurisdiction that the Board may lawfully delegate, which the Board deems appropriate, and which the Board has not otherwise reserved to itself. Health and Safety Code sections 39515, 39516, 39600, and 39601. The Board's delegation of authority to the Executive Officer to consider changes to ARB regulations is an established method for amending regulations when, for example, the Board determines that certain changes do not require Board consideration. See, e.g., *Rulemaking to Consider Amendments to the Tables of Maximum Incremental Reactivity (MIR) Values*, <http://www.arb.ca.gov/regact/2009/mir2009/mir2009.htm>. Therefore, there is legal authority and precedent for this type of delegation of authority to the Executive Officer.

Substantive changes to the regulation, proposed either by the staff or by regulated parties, would be considered by the Executive Officer through a formal rulemaking process, as provided in the regulation pursuant to the delegation of authority in Resolution 09-31. By making such changes through a public process, interested stakeholders and other members of the public would be allowed to review and comment on the proposed changes. This helps to ensure transparency and accountability in the LCFS program.

C-120. Comment: Because the "carbon intensity values represent the currency upon which the LCFS is based," the proposed regulation would enable one individual, the Executive Officer, to essentially pick fuel winners and losers based upon widely varying data determining significant impacts such as land use change. (CERA2)

Response: The commenter's claim notwithstanding, the Executive Officer's action to approve or disapprove a proposed new or modified fuel pathway under Method 2A or 2B will be neither arbitrary nor capricious, but rather it will be subject to the specific requirements set forth in the LCFS regulation, the delegation of authority in Resolution 09-31, the APA's rulemaking provisions, and other applicable provisions in State law. See also response to Comments C-111 through C-115 and C-119.

C-121. Comment: Already ARB staff is picking winners and losers every day as they pick which values to employ among competing self-interests. For instance, the ISOR describes that in computing one input "ARB staff and GTAP modelers assume that 25 percent of the carbon stored in the soil is released when land is cultivated. We believe this value is a reasonable compromise given the variability in data (emphasis added). "When there are marginal differences in values between particular fuels on the Lookup Chart, we believe the ARB invites financial incentives for fraud, being flooded with opt-in values to get under the baseline, and the agency having to make a "compromise" situation, subject to

competition from new fuel challengers. The proposed LCFS regulation worsens this dynamic by affording the discretion to make these "compromise" decisions in one individual, even if it is after a public review process. (CERA2)

Response: The primary purpose of the LCFS is to provide an incentive for the use of transportation fuels with low-carbon intensity values. Contrary to the commenter's claim, the regulation is not expected to invite fraud. The regulation achieves an important balance between the creation of Lookup Tables (for fuel pathways that will not vary substantially between different producers) and the administrative burden that would be created by allowing fuel producers to establish their own unique carbon intensities for fuel pathways with minor differences from those in the Lookup Tables. This balance is achieved via the Method 2A and 2B process, which provides flexibility to fuel producers who develop and use different pathways with low carbon intensity values while maintaining transparency on that process (similar to a scientific journal's peer review process). The use of an Executive Officer approval process is an established process permitted under State law, which helps ensure that only the most scientifically valid and relevant data are used to establish the carbon intensity values for different pathways.

See also response to Comments C-111 through C-115 and C-119 through C-120.

C-122. Comment: CARB's failure to complete the LCFS rule before this adoption hearing places the regulated community and the public in an untenable situation. The missing elements of the rule (such as key carbon intensity values, and a mechanism for tracking and reconciling carbon intensity credits and debits) are so essential to the rule's functioning that it is not possible to assess the rule as a whole and comment upon whether its structure and approach are reasonable and workable, or determine whether compliance with the rule is feasible. (WSPA2)

Response: As noted previously, this FSOR covers the regulation as adopted except for the incomplete pathways for a severability clause and biodiesel and renewable diesel from Midwest soybeans. All other provisions in the regulation as adopted were subject to the 45-day and two supplemental 15-day comment periods. It is ARB's intent to incorporate before the end of the rulemaking (i.e., March 4, 2009) the severability clause and the additional pathways for biodiesel and renewable diesel made from Midwest soybeans. See also response to Comments C-32, C-52, C-55, and C-95. Those additional pathways are being completed and will be released for a supplemental public review and comment period; comments received pursuant to that supplemental period will be addressed in a separate FSOR.

With regard to the mechanism for tracking and reconciling credits and debits, ARB staff will also have the online reporting tool in place before the end of the rulemaking and certainly well before the first quarterly report is due (May 31, 2010). If the commenter is referring to section 95488 ("Cap and Trade"), that section is merely a placeholder that is intended to specify provisions, if needed, which will govern the LCFS regulation's

interaction with the AB 32 Cap-and-Trade regulation currently under development. Because the Cap-and-Trade program has not yet been developed, the lack of any substantive provisions in section 95488 has no effect on the LCFS regulation.

C-123. Comment: In the alternative, CARB should consider adopting a new pathway for low energy, non cracking refineries to avoid punishing such refiners for their lower carbon intensity processes and ensure that they are not further economically disadvantaged by requiring refiners such as Paramount to acquire LCFS credits or supply alternative fuels. (PP1)

Response: This issue is similar to that raised by Kern Oil and its request for differential treatment of small refineries under the LCFS program. As such, the response to Comment C-118 would apply to this comment as well.

Comments on GREET, Life-Cycle Analysis, Lookup Tables

C-124. Comment: The regulations should provide:

- a. The methodology to be used for each source and sink in a fuel lifecycle,
- b. in particular, the land use change emissions methodology, but equally the biomass cultivation emissions methodology,
- c. the databases which will be used (emission factors, regional primary energy mixes, etc, vehicle emission factors, etc), and
- d. the specific version of the Software Compliance tool containing all of the above which will apply under the regulations. (SHELL)

Response: The regulation approved with modifications will accomplish these. For each pathway in the LCFS, a reference is provided that contains the details for the lifecycle analysis for the pathway, including both the direct and indirect impacts. These are provided in the supporting document for that pathway. Other relevant information is contained in the Appendices to the ISOR. The software compliance tool (now known as the LCFS Reporting Tool or LRT) is undergoing beta testing and will be available for public use in early 2010.

C-125. Comment: The Regulations should specify the carbon intensity calculation approach along with the embedded emissions models, methodologies (including land use change methodology) and databases that apply under the regulation. The regulations should also lock down a specific version of the carbon intensity calculation software tool. Any updates to these should be done through rulemaking.

Section 5.1 of the draft outline states that CARB will develop, use, and provide a copy of the latest version of a modified ARB model. Similarly, section 5.3.5 states that CARB will use the “latest” land use change methodology. It is not clear whether CARB intends to incorporate the specific version of the models and land use change methodology that will be used under the regulations in the

regulations themselves. (SHELL)

Response: The commenter is referring to older versions of the regulation that were released prior to the start of the formal rulemaking process. The regulation has since been modified to incorporate specific versions and dates of models, databases, and methodologies as suggested by the commenter (e.g., CA-GREET v.1.8b (February 2009) and the GTAP Model (February 2009)). Because these are incorporated by reference into the regulation, changes to these models, databases, and methodologies would need to undergo a rulemaking procedure.

As noted previously, the staff is preparing a guidance document to assist regulated parties in how to apply under Method 2A and 2B of section 95486(c) and (d), respectively. This will provide additional tools and information that will help stakeholders establish new or modified carbon intensities of fuels that will be used for compliance. The GREET model and the GTAP model are both publicly available, and it is staff's understanding that others have used the models and replicated the results of the staff's analysis using the models.

C-126. Comment: The LCFS standard that meets your final approval should include:

- a. Elimination of lookup tables to determine carbon intensity
- b. In place of lookup tables, utilization of tools that are currently available to assign carbon intensity values based on individual plant production practices. (ICM1)

Response: The need to incorporate the Lookup Tables into the regulation was addressed in response to Comment C-65. And the balance achieved by having a set of Lookup Tables along with a process for modifying those Lookup Tables (i.e., Method 2A and 2B) was addressed in response to Comment C-121.

C-127. Comment: The following proposal outlines our recommendations to most efficiently categorize carbon intensity values of ethanol by using up-to-date agricultural and process production data, eliminating incorrect and inefficient labeling methods, and eliminating the time-consuming hearings that would be necessary to adjust lookup table values as more efficient production practices further reduced the carbon intensity of ethanol. Rather than approve the use of any carbon model or the CA-GREET-driven lookup tables, ICM recommends that CARB Board of Directors directs staff to specify a set of pathways and databases that must be considered in any carbon accounting model to accurately determine the carbon intensity of any source of ethanol. It will then be up to the producer to determine how to most accurately determine the carbon intensity of ethanol to be blended in California. (ICM1)

Response: The need to incorporate the Lookup Tables and Method 2A and 2B into the regulation was addressed in response to Comments C-65 and C-121. Further, in Resolution 09-31, the Board directed staff to continue working with stakeholders to

ensure that the carbon intensity values in the regulation for ethanol and other fuels and blendstocks reflect the most recent data, scientific understanding, assumptions, and modeling approaches for calculating carbon intensity and to pursue a certification-type process for approving carbon intensity values. Once we successfully incorporate into the regulation a certification process for updating carbon intensity values and other elements of the regulation, the need to conduct formal rulemakings to make these changes can be eliminated.

In approving the regulation, the Board approved the Lookup Table approach. This avoids the need for individual producers using the same feedstocks and processing technology from having to establish their own carbon intensity values. Thus, the Lookup Tables provide the most scientifically valid, fair, and equitable approach for calculating the carbon intensities of fuels that are produced from the most commonly used pathways and processes. For these pathways and processes, the Lookup Tables ensure that the same calculation methodologies and approaches are used, thus ensuring that any differences in calculated carbon intensities reflect real differences in the fuel's lifecycle carbon emissions.

In Resolution 09-31, the Board approved the use of the GREET and GTAP model approaches for calculating the carbon intensity of transportation fuels. The Board determined that the approaches embodied in the regulation reflect the best available and most scientifically-defensible information. Nevertheless, the Board recognized that the science in this area continues to evolve and that the regulation may need to be refined in the future to reflect such developments.

To this end, the Board directed staff to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effects modeling. Also, two program reviews are mandated by 2012 and 2015. These program reviews will cover, among other things, advancements in full, fuel-lifecycle modeling. Finally, the Board directed staff to develop specific criteria for conducting Lookup Table modifications through a certification process, and propose amendments to the regulation, if appropriate, at the December 2009 hearing.

C-128. Comment: Rather than categorize ethanol broadly in comparison to gasoline, ICM recommends that ethanol is categorized based on actual production practices at individual ethanol facilities. Ethanol starch feed stocks, e.g., corn, milo, and wheat all have different carbon intensity based on agricultural and production practices, and the carbon intensity of ethanol production varies based upon the energy source used to power the production facility. The ICM Eenergy Model (one of many models available today) is a proprietary business model designed specifically to determine the field-to-wheels carbon lifecycle intensity of fuel ethanol produced by any ethanol plant, anywhere in the world. This tool quantifies potential mitigation strategies to reduce a plant's carbon footprint, based on a full field-to-wheels LCA. It is recommended that before being used to provide an LCA for carbon accounting purposes to promote reductions in motor vehicle carbon fuel intensity, all carbon models (public and private) be vetted to

meet carbon accounting requirements established by the United Nations Intergovernmental Panel on Climate Change, the World Resources Institute Greenhouse Gas Protocol, and ISO 14040 standards for LCAs. If command-and-control carbon intensity standards (i.e., mandated percent reductions from gasoline baseline) are adopted combined with a market-based approach to promoting global reductions of motor vehicle fuel carbon content, any carbon model that meets a specified set of standards (international, country by country, or U.S.) must be allowed by the regulatory agencies to promote the lowering of carbon emissions from cars without feared bureaucratic impediments. Each ethanol plant can easily maintain its own carbon model (e.g., ICM Econergy Model) for the purpose of documenting compliance with the proposed carbon reduction standard of Phase I and Phase II. Any command-and-control rulemaking without a market-based solution may actually serve to create perverse incentives if producers, distributors, and blenders are not rewarded by the marketplace for voluntary carbon mitigation in order to reduce their gasoline's carbon content to below the Phase I and Phase II reductions (standards). All ethanol is not equal from a full LCA carbon intensity basis, and ethanol should not simply be labeled related to the plant's energy source (i.e., natural gas ethanol, coal ethanol or biomass-produced ethanol) as has been recently proposed. (ICM2)

Response: The need for and rationale underlying the Lookup Tables are discussed in response to Comments C-65 and C-121.

The approach suggested by the commenter is neither necessary nor appropriate given the Board's specific findings with regard to the LCFS regulation. In Resolution 09-31, the Board determined that the approved regulation was developed using the best available economic and scientific information. This includes the staff's use of the CA-GREET and GTAP models. The Board further found that the regulation will achieve the maximum technologically feasible and cost-effective GHG emissions reductions from transportation fuel used in California and will encourage early compliance with the regulatory requirements. Moreover, the Board found that the staff performed the complete lifecycle analysis of several fuels and assigned scientifically defensible carbon intensity values to these fuels. Finally, the Board found that indirect land use change was appropriately included as part of the lifecycle analysis conducted by staff.

C-129. Comment: To facilitate the harnessing of market forces to drive the nation's transportation sector toward lower carbon fuel usage, a national fuel-rating system should be developed. Based on the output of a plant specific lifecycle analysis, the ethanol produced by a specific individual ethanol plant would be rated on its GHG performance relative to gasoline. The fuel rating would provide the basis for fuel blenders to choose the ethanol product that best enables them to meet a national clean-fuel standard. The fuel rating would eventually also be displayed on the fuel pump to empower motorists to make a fuel choice based on its relative "green-ness" if they so desire, thereby enabling them to directly participate in a clean-energy economy. Thus, we will increase our energy

independence, keep US dollars in our own economy, and continue to create the “green collar” jobs that are the foundation of our future economic prosperity.
(ICM2)

Response: The Board has no authority to impose a national clean-fuel standard, as suggested by the commenter. This suggestion is best addressed at the federal level in the Renewable Fuels Standard program being implemented by U.S. EPA. With that said, the LCFS is already designed to achieve some of the objectives espoused by the commenter. For example, the regulation provides a type of fuel “rating” by assigning carbon intensity values to the various fuels and blendstocks based on their “well-to-wheel” or “seed-to-wheel” carbon intensities. By selecting appropriate blends of low-carbon fuels and blendstocks, fuel providers can determine on an annual basis the carbon intensity of their overall fuel pools, and the regulation requires that the carbon intensity of fuel pools be reduced by 10 percent by 2020.

However, it is impractical to require fuel marketers (i.e., gas stations) to label pumps according to the fuels’ “green-ness” or carbon intensity. This is because a fuel’s carbon intensity cannot be determined in a lab with a test procedure, which makes it difficult to track a fuel’s carbon intensity on a batch-by-batch basis. Also, when a new batch of fuel is mixed with fuel that’s already in a storage tank at a gas station, the resulting blend will have a composite carbon intensity that is virtually impossible to calculate with certainty. Even if one could calculate the carbon intensity of the fuel in a storage tank on a real-time basis, the continual changes in the fuel’s carbon intensity because of constant fuel removal and replacement would make pump labeling impractical. Therefore, the suggested labeling program would be very difficult and impractical to implement with the LCFS program.

C-130. Comment: However, some flexibility is provided for refiners to modify the default values which underlie the carbon intensity calculation, which could be used to increase the relative share of diesel offered above the CARB baseline inventory assumptions. (SCAQMD1)

Response: The LCFS is a carbon-intensity performance standard and does not establish requirements for diesel consumption compared to gasoline consumption.

C-131. Comment: GREET contains forecasts of efficiency improvements for certain pathways, which implies that the carbon intensity changes over time. Will the default CARBOB intensity change with calendar year, or will it be static? How about the carbon intensity lookup table? Will those estimates be a function of calendar year or will they be static? (WSPA1)

Response: The ARB anticipates changing the default value for the carbon intensity of CARBOB only if additional information becomes available that indicates that the current parameter values used in GREET to calculate the carbon intensity value are no longer valid and need to be changed. The staff will monitor the validity and appropriateness of the carbon intensity values produced by GREET during the implementation of the

regulation and make any needed changes during the scheduled program review periods. Such changes, if needed, would be made pursuant to a formal rulemaking. Also, section 95489 requires formal program reviews by 2012 and 2015; these issues can be addressed as part of those reviews.

C-132. Comment: BP believes that the petroleum industry should have the ability to earn an improved pathway as a result of substantial investments to reduce carbon output, such as Carbon Capture Sequestration (CCS). The current Proposed LCFS Regulation appears to rule that Method 2A and 2B are not available to CARBOB and Carb Diesel. Section 95486 (a)(1) says, "A regulated party for CARBOB, gasoline or diesel fuel must use Method 1, as set forth in section 95486 (b)(2)(A) to determine the carbon intensity of each fuel or blend stock for which it is responsible. The rule goes on to say in the next subsection that, "A regulated party for any other fuel or blend stock must use Method 1unless the regulated party is approved for using either Method 2A or Method 2B..." BP requests that section a(1) read like a(2) whereby producers of gasoline and diesel can use the Method 2A and 2B as well. BP also requests that the threshold to apply for Method 2A be changed from 5 g/MJ to 10 percent of the source -to-tank emissions. (BP1)

Response: The ARB will give credit for petroleum industry strategies that reduce carbon emissions through the use of CCS technologies in other AB 32 regulations that pertain to the petroleum refining and production.

The difference in carbon intensity values that would result from allowing obligated parties to use unique carbon intensity values for their CARBOB and diesel fuels are not expected to be great enough to justify the increased complexity and difficulty of enforcement. Allowing CCS as suggested by the commenter would mean that CARBOB and diesel from individual producers would no longer be fungible and every batch would have to be monitored. The most credit that could be generated would be less than 5 gram per CO₂ equivalent per MJ, the threshold established for 21 new subpathways to be established under Method 2A.

In the LCFS, the carbon intensity of both the production and refining of crude are fixed. This is to prevent the "shuffling" of crudes (i.e., switching to a crude that is easier to refine as way to comply while the "avoided" crude is refined elsewhere, resulting in no net reduction in GHG emissions worldwide).

Also, refinery efficiency is an example of a parameter whose value would not vary enough from refinery to refinery to justify allowing individual refiners to use their own refinery efficiency values for calculating the carbon intensities of the fuels they produce. The staff estimates that the change in overall carbon intensity of gasoline or diesel produced from conventional crude due to differences in refinery efficiency would be less than one gCO₂e/MJ. The administrative burdens of including a provision that would allow producers to use individual refinery efficiencies would be too great to justify such a small improvement in the estimated carbon intensity of the fuel produced. Also,

emissions from refining in California will be subject to control under other AB 32 provisions to reduce greenhouse gas emissions from stationary sources.

With regard to the suggestion to change the Method 2A threshold from 5 grams to 10 percent, this was addressed in response to Comments C-82 and C-83.

C-133. Comment: The well-to-wheel system boundaries as currently defined in many tools could provide future risks of double counting emissions or reductions e.g. emissions associated with fertilizer production counted in the chemical industry are also counted in the biofuel calculation. (VALENTE)

Response: The commenter did not provide a specific example of how the particular calculations used in developing the regulation may contain double counting. Therefore, we will assume the commenter is suggesting a heightened awareness of the possibility of double counting in the circumstances noted. The ARB staff will endeavor to ensure that double counting of emissions and emission reduction does not occur under those circumstances.

C-134. Comment: The ISOR states that the "scope of the standard is designed to capture the diverse fuel portfolio available today and in the near future, while offering a fuel-neutral platform in which alternative fuels can be incentivized without choosing winners or losers (emphasis added). However, the "default Lookup Table" does in fact pick winners and losers above or below the relative gas or diesel baselines. ARB staff directly picks those winners by calculating the carbon intensity, which can and has become very political given the great scientific uncertainties of calculating soil payback times, land use change impacts, and all of the other uncertainties in calculating lifecycle analysis and land use change that ARB staff continues to analyze. (CERA1)

Response: The creation of Lookup Tables in the regulation does not constitute choosing winners and losers. The Lookup Tables simply reflect the results of the analysis of direct and indirect GHG emissions for each of the listed pathways' fuel lifecycle. In Resolution 09-31, the Board found that the regulation as approved, which includes the Lookup Table approach, uses the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective GHG emission reductions from transportation fuel used in California. The Board also found that the approved regulation encourages compliance with the LCFS requirements. Moreover, the Board found that the staff had conducted complete lifecycle analyses for the fuels listed in the Lookup Tables and that indirect land use change had been appropriately included as part of those lifecycle analyses.

It is indisputable that some fuels have higher carbon intensities than other fuels in the tables. This simply reflects the fact that there are GHG differences in how the different fuels are produced, marketed, and used (e.g., ethanol from corn, sugarcane, cellulosic, etc.); there are even GHG differences in how the same fuel is produced (e.g., ethanol from corn using wet mill, dry mill, etc.). Reflecting these differences in the Lookup

Tables no more constitutes “picking winners and losers” than using testing and modeling to assign different emission rates to each new automobile family sold in California, photochemical reactivities to individual organic compounds used in consumer products, or volatile organic compound (VOC) contents to various consumer products.*

The regulation was modified to include Lookup Tables that provide carbon intensity values for those fuel pathways that are the most likely pathways at this time. This was done so fuel producers using these pathways will be fairly and equitably treated. If individual fuel producers believe that the carbon intensities of the fuels they produce are different from those in the lookup table, the producers have the option of using the Method 2A and 2B provisions in section 95486 to propose and establish alternative carbon intensity values for their individual pathways.

C-135. Comment: In addition, Kern processes light San Joaquin Valley low sulfur crude. Yet, in the LCFS assumptions, Kern is being averaged in with larger refiners that process heavy, high sulfur crudes that require significantly more energy to produce, transport and refine. (KORC1)

Response: The LCFS standard is the same regardless of whether light, low sulfur crude or heavy, high sulfur crude is used as the feedstock. Therefore, the amounts of low carbon intensity fuels that would have to be used to meet the LCFS standard are the same, regardless of the type of crude feedstock. The difference in carbon intensity between the refining of heavy and light San Joaquin Valley crudes is not great enough to justify having different baseline carbon intensity values and different LCFS standards for the two types of crude oil. Similarly, the difference in carbon intensity values for fuels produced at non-cracking refineries compared to fuels produced at cracking refineries is not great enough to justify the additional administrative and enforcement burdens that would result if the regulation permitted individual refineries to establish their own carbon intensity values for CARBOB, gasoline and diesel.

C-136. Comment: Our recommendation is that CARB staff send a letter to the ISO or ASTM Committee in Sweden that was responsible for making decisions about carbon life cycle emissions for petroleum and request the minutes of the meeting relating to the recommendations of the Scientific Subcommittee providing input to the Committee. We think this is a very important step for CARB before finalizing the low carbon rule as it would dramatically change the assumptions about carbon emissions from the principal petroleum fuels being compared with biofuels or other measures. Economic weighing means that a crude refining stream would first be given an energy value as determined by the GREET model. It would then require an allocation of emissions on the basis of the economic value of the products from the petroleum refining stream. Since about 40 percent of the petroleum stream is a low value bunker fuel, asphalt or other tars, this would immediately have a strong impact on the petroleum emissions assigned to all of the remaining refinery streams (primarily distillates, gasoline and jet fuel). This economic weighing is more than justified because it was recommended by

* 13 CCR §1961; 17 CCR §§94700, 94701; and 17 CCR §§94507-94517, respectively.

the ISO Scientific Committee and would provide a consistent approach with other regulated carbon emission sectors. The other sectors now regulated in Europe under their cap and trade program must undergo “economic weighing” and it would be logical for CARB to do the same in its cap and trade program. Yet this would immediately create an inconsistency with the way petroleum is handled in the baseline assumptions about carbon emissions. (CO2STAR)

Response: In Resolution 09-31, the Board found that the current approach used by GREET to calculate carbon intensity values in the regulation is accurate, scientifically valid and defensible, and based on the best available data. Also, the reasons for “economic weighing” suggested by the commenter are generally inapplicable to California refiners. This is because major California refineries are designed to refine crude oils to maximize motor vehicle fuel production. California refineries are built to process nearly all crude into transportation fuels. Very little bunker fuel or similar low value products are produced as a result.

C-137. Comment: We have looked at several pathways for use of bagasse that would greatly improve net fuel and energy production from a single ton of sugar cane. One assumption of the UNICA study is that bagasse will continue to be used for power production in Brazil. While this could be true in Southern Brazil where there is a much higher contract price for electricity, we think this is unlikely in the Northeast where there is a much lower electric price and longer transport distance to move electricity to markets. Use of bagasse to produce fuel is a much more profitable option because of the higher value of fuel and the higher conversion rates of bagasse to fuel with some technologies.

A technology that we provide as an example in this category is Terrabon’s technology that uses a methane-suppressed anaerobic digestion process to produce either ketones or carboxylic acid and then converts these chemicals to bio-gasoline or mixed alcohol with a hydro-treating process. The company has already demonstrated the process in a research facility and is now building an industrial proof of concept scale plant that will produce 300 gallons of bio-gasoline per day with funding from US Dept. of Energy and private partners. The feedstock is currently sorghum in the biomass pile but various biomass will be tested over the course of the summer, 2009 including Municipal Solid Waste (MSW). The theoretical conversion efficiency of the technology is up to 65 percent, although the current conversion efficiency is about 50 percent. The residue from the process can also be solar dried and used in the same boilers now providing steam through the drying of wet bagasse. The extraction of liquids from the biomass piles also results in a biomass that is much drier than bagasse with high energy density. The capital cost is also reasonable (\$2.50/installed gallon) and expected to drop to \$1/gal. (CO2STAR)

Response: The regulation was modified to include in Lookup Table 6 (section 95486(b)(1)) three separate pathways for sugarcane ethanol. Two of those pathways involve electricity co-product credit (i.e., from the use of bagasse to generate electricity,

as described by the commenter). Therefore, the Lookup Table addresses the commenter's concern by establishing pathways that reflect sugarcane ethanol processes either involving the use of bagasse to generate electricity or not involving such electricity co-product credit. The use of bagasse for animal feed, as a fuel feedstock (e.g., in cellulosic ethanol processes), or to generate electricity is discussed in the ISOR on pages ES-16, III-3, III-4, III-15, IV-7, and VIII-17.

To the extent the commenter may be implying that ARB's carbon intensity analysis looks only at combustion, we disagree. The approach used in the LCFS is a well-to-wheels approach; thus, this aspect of the comment does not apply if the commenter is implying otherwise. Under the LCFS, the carbon intensity of a fuel's pathway is determined over the entire lifecycle of the fuel, not just the combustion.

C-138. Comment: One of the current mistakes made in the scientific studies about production of oil for biodiesel, renewable diesel, or Hydrotreated Renewable Jet (HRJ) fuel is that the industry will continue to produce these fuels using the same methods and crops now being used. We think that is unlikely because of sustainability concerns with each of the current oil stocks and the potential to develop much better production economics and sustainability using new crops and approaches to agriculture. These approaches are not considered by the life cycle carbon scientists because they are not oils in large scale commercial production. However, they could dramatically change the carbon life cycle assumptions about biofuels and require adaptation of the GREET CA model to provide the optimum substitution benefit from the co-development of both food and fuel on the same fields. (CO2STAR)

Response: As noted in response to Comment C-43, during the implementation of the LCFS, the ARB staff will continue to work to improve the understanding of various factors that may affect the direct and indirect contributions to GHG emissions associated with transportation fuels. In Resolution 09-31, the Board directed the Executive Officer to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effects analysis of transportation fuels. The Executive Officer was further directed to return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. Moreover, section 95489(a)(3) requires the Executive Officer to consider, among other things, advances in full, fuel-lifecycle assessments as part of the two program reviews built into the regulation. The Board's directives and the regulation's required program reviews will ensure that the LCFS regulation will continue to reflect the dynamic changes in the biofuel industry as well as other fuel sectors.

C-139. Comment: The proposed default & opt-in system will undermine the achievement of "real" emission reductions. We oppose averaging of values that may in effect ignore important emissions factors in a fuel's pathway. We support the most accurate assessment of total emission impacts as possible. The ISOR states: "The first method, referred to as Method I, establishes default values for a

number of specified fuel pathways. Regulated parties may choose to use the default pathways to calculate credits and deficits." We oppose the adoption of default emission estimates as "poor surrogates for actual measurements. With margins of error ranging from fifty percent to one hundred percent, emissions factors are highly uncertain, making claimed emission reduction difficult to verify. They can readily be adjusted to report emissions as being higher or lower, since at best they represent educated guesses of actual emissions." Thus, to the maximum extent feasible based upon the "most accurate" and "best available" climate science available, we recommend that ARB measure actual emissions of each fuel provider versus an averaging system. If ARB chooses to adopt a default estimate system, we recommend that default values should be as "pessimistic" as possible. Also, we oppose the proposal to allow the Executive Officer to amend and approve subsequent amendments to the default "Lookup Table" at will. (CERA2)

Response: The use of Lookup Tables for establishing the carbon intensity values for gasoline, diesel, and other fuels that will most likely be used to comply with the regulation is the best way to ensure that carbon intensity values are fair, equitable, and reflect the most accurate and relevant scientific data and information. Differences in individual fuel producers' carbon intensity values due to differences in production practices are not great enough to justify allowing each producer to establish his own carbon intensity value. The Lookup Tables ensure that the carbon intensity values for common pathways will use consistent data and estimation methodologies. Any differences in carbon intensity values in the Lookup Tables will reflect real differences in lifecycle carbon emissions rather than differences in calculation approach or assumptions. Contrary to the commenter's claim, the use of Lookup Tables will help ensure that the emission reductions of the regulation are preserved, and will not undermine the regulation.

With respect to the comment regarding the Executive Officer, allowing the Executive Officer to make changes to the regulation after a duly noticed public meeting that provides for public input is an established approach for amending regulations. This has been done in the past, for example, when the Board decides it is not necessary for it to consider technical amendments to a regulation the Board has approved. State law provides that the full Board can delegate to the Executive Officer any duty that it deems appropriate. For additional discussion on this issue, see response to Comment C-119.

C-140. Comment: We urge CARB to adopt resolution language that would address the concerns voiced in the E2 letter, including expeditiously approving pathways for advanced biofuels and identifying feedstocks with zero indirect land use change. (NRDC3)

Response: Resolution 09-31 adopted by the Board directs the staff to provide a preliminary list of feedstocks that have caused zero land use change. Also, the regulation was modified to establish in Lookup Table 7 (section 95486(b)(1)) pathways for biodiesel (produced from waste oil) and renewable diesel (produced from tallow). As

noted in response to Comment C-32, it is ARB's intent to incorporate before the end of the rulemaking additional pathways for biodiesel and renewable diesel made from Midwest soybeans. Those additional pathways are being completed and will be released shortly for a supplemental public review and comment period; comments received pursuant to that supplemental period will be addressed in a separate FSOR. And as noted in response to Comment C-30, other fuel pathways, including pathways for "advanced renewable diesel," can be submitted for the Executive Officer's consideration under Methods 2A and 2B, as provided in section 95486(c) and (d).

The ARB staff will continue to work with stakeholders to develop carbon intensity values for fuel pathways that will likely be used to achieve compliance with the regulation. The staff will also work with these stakeholders on the indirect land use change effects and to understand which other fuel pathways have zero or non-zero indirect land use change effects. The staff will also publish guidelines addressing these issues which will include information on what biofuels are not expected to have indirect land use effects. Staff is conducting these activities pursuant to the Board's directives in Resolution 09-31 and the two mandated program reviews in section 95489.

C-141. Comment: We remain troubled today that we are adopting this regulation with the many uncertainties that are still within it, and therefore we cannot support its adoption in this form, regardless of how meritorious the goals may be. We do know that there are lots of carbon intensity values for future fuel pathways that have not yet been determined, and that's been noted in previous comments. (WSPA3)

Response: The ARB believes that there is sufficient certainty in the fuel pathways that are most likely to be used for compliance to adopt the regulation now and to begin to implement it. During the implementation of the regulation, the staff will continue to work with stakeholders in an effort to reduce the uncertainties of the fuel pathways that will likely be used to comply with the regulation. As part of this effort, the staff will work on the land use change effects and to better estimate the emissions from these effects. The ARB staff will propose any needed changes to the regulation and the carbon intensity values if there is valid and relevant scientific information supporting such changes. Resolution 09-31 directs the staff to establish an expert work group to assist in this.

The ARB has developed and published additional pathways and is currently developing a credit and debit tracking mechanism. However, it is important to note that regulated parties can and are expected to conduct trades of credits with no interaction with the ARB other than to report the results of those trades on an annual and quarterly basis, as specified in the regulation's reporting and recordkeeping provisions (section 95484(c) and (d)). The ARB expects that by the end of this year all of these additional program elements will be available to stakeholders so that they can better develop their compliance strategies and assess the most feasible compliance options.

C-142. Comment: We wish there was more pathways in front of you today related to

energy from -- fuel from waste. But we're confident that you're heading in the right direction and we look forward to continue to working with you and your staff as those pathways continue to be developed in the near future. (WM3)

Response: The regulation, as approved with modifications, establishes in Lookup Tables 6 and 7 (section 95486(b)(1)) various waste-to-fuel pathways, including CNG and LNG from landfill gas, CNG and LNG from dairy digester gas, biodiesel from used cooking oil, and renewable diesel from tallow. As directed in Resolution 09-31, the staff will continue working with stakeholders to identify additional fuel pathways for possible incorporation into the Lookup Tables. Such new waste-to-fuel pathways could involve anaerobic digestion, thermochemical conversion of biomass feedstocks, and additional LNG pathways. The Board directed the staff to identify a priority list of specialized fuel pathways for further development and to report that list with a proposed development schedule to the Board at the December 2009 hearing.

Compliance Schedule

C-143. Comment: We are concerned about meeting the 2015 to 2020 interim carbon intensity targets. We have the following recommendations to mitigate the issue:

- a. Because of the difficulty in predicting advances in technology we believe triennial reviews of the program must be carried out and the interim target feasibility be assessed. These reviews should be made a requirement in the LCFS regulation.
- b. ARB should include some comparative analysis showing ARB's compliance schedule in comparison with the federal EISA schedule.
- c. The fact the European Fuels Directive reduced their LCFS target for transportation fuels from 10 percent to six percent due to a concern over feasibility. It is our understanding that if the EU Commission finds, through its own periodic reviews, that a 10 percent reduction is feasible, it would likely be reinstated. This same analysis and flexibility should be addressed in the California LCFS program documentation. (WSPA1)

Response: Our responses are outlined below:

- a. The Board determined that periodic reviews should be done, but the suggested triennial reviews are unnecessary. In Resolution 09-31, the Board directed the Executive Officer to monitor the implementation of the regulation and propose amendments when warranted. Reso. 09-31 at 18. Further, the modified text of the regulation released for public comments on July 20, 2009, includes a provision for two program reviews by 2012 and 2015. The specifics of the program reviews were presented to the Board for its consideration at the April 2009 hearing. Attachment B to Reso. 09-31. Among other areas, these reviews will evaluate the progress of the production and availability of low-carbon fuels. Based on the Executive Officer's review, the LCFS compliance schedule could be adjusted if quantities of low-carbon fuels are found insufficient to meet the goals of the compliance schedule, or the

Executive Officer may recommend other measures to address this concern. Based on the specificity of the two program reviews in section 95489, the Board determined the two reviews will provide sufficient information with which to make program corrections or take other measures, if needed.

- b. This has been done and shows that the schedules for the two programs do not conflict. A comparison of the two programs was provided in the Staff Report (at ES-5 and X-1, 2) and is summarized below.

The RFS2 requires that 36 billion gallons of biofuels be sold annually by 2022, of which 21 billion gallons must be “advanced” biofuels and the other 15 billion gallons can be corn ethanol. The advanced biofuels are required to achieve at least 50 percent reduction from baseline lifecycle GHG emissions, with a subcategory required to meet a 60 percent reduction target. As noted in the ISOR, RFS2, by itself, achieves only approximately 30 percent of the GHG reductions projected under the LCFS program. The RFS2 targets only biofuels and not other alternatives; therefore, the potential value of electricity, hydrogen, and natural gas are not considered in an overall program to reduce the carbon intensity of transportation fuels. In addition, the targets of 50 percent and 60 percent GHG reductions only establish the minimum requirements for biofuels. It forces biofuels into a small number of fixed categories and thereby stifles innovation. Finally, it exempts existing and planned corn ethanol production plants from the GHG requirements, thus providing no incentive for reducing the carbon intensity from these fuels.

By contrast, the LCFS regulates all transportation fuels, including biofuels and non-biofuels, with a few narrow and specific exceptions. Thus, non-biofuels such as compressed natural gas, electricity, and hydrogen play important roles in the LCFS program. In addition, the LCFS encourages greater innovation than the federal program by providing important incentives to continuously improve the carbon intensity of biofuels and to deploy other fuels with very low carbon intensities.

- c. As indicated in response to a. above, with the provision in section 95489 for two reviews, along with the Board’s directive in Resolution 09-31 for staff to monitor the LCFS implementation, the LCFS program allows for a similar analysis and flexibility as the EU programs referenced by the commenter.

C-144. Comment: We believe the goal of one percent carbon reduction per year is very conservative and could be much greater given the volatility and cost risk associated with dependence on petroleum (as we saw in 2008). (CO2STAR)

Response: The objective of the regulation is to achieve maximum technologically feasible and cost effective GHG emission reductions. The schedule as approved is “back-loaded” in that much lower percentage of progress is required in the early years compared to the later. This is to allow the more advanced fuels and vehicle technologies time to be commercialized. This is the same approach U.S. EPA has taken for their renewable fuels program. Furthermore, the current reduction targets

meet the requirements of the Executive Order S-01-07, i.e., to reduce the carbon intensity of transportation fuels in California by at least 10 percent by the year 2020. Under the approved compliance schedule, the estimated GHG emissions reductions for the full fuel lifecycle, including fuel production through combustion are about 23 MMT CO₂e in 2020, of which about 16 MMT are estimated to be achieved in California. These reductions account for almost 10 percent of the total GHG emission reductions needed to achieve the AB 32 mandate of reducing GHG emissions to 1990 levels by 2020.

Finally, with regard to the commenter's concern about volatility and cost risk associated with petroleum dependence, the regulation as approved should help mitigate this issue by creating greater incentives for clean transportation technology and stimulating the production and use of alternative, low-carbon fuels in California.

C-145. Comment: We recommend an accelerated implementation schedule for the diesel fuel pool with more stringent carbon reductions. California's biodiesel industry, which produces the majority of its fuel from waste sources, has the ability today to create immediate and substantial carbon reduction, using currently available technology on both production and consumption ends of the spectrum. (GDSF, SFB1, SFB2, NBB, COI).

Response: In Resolution 09-31, the Board determined that the regulation as approved, including its compliance schedule, was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective GHG emission reductions from transportation fuel used in California. The Board also determined that the regulation will encourage early compliance with the requirements. Further, the Board determined that no reasonable alternative considered, such as the one suggested, would be more effective at carrying out the purpose for which the regulation is proposed or would be as effective as and less burdensome to affected private persons and businesses than the regulation.

The standards are “back-loaded;” that is, there are more reductions required in the last five years than the first five years. This schedule allows for the development of advanced fuels that are lower in carbon than today’s fuels and the penetration of plug-in hybrid electric vehicles, battery electric vehicles, fuel cell vehicles, and flexible fuel vehicles. It is anticipated that compliance with the LCFS will be based on a combination of strategies involving lower carbon fuels and more efficient, advanced-technology vehicles.

C-146. Comment: Change the LCFS baseline year from 2010 to 2005 or 2004 (the most recent year before the LCFS regulatory process began). The 2007 Technical Analysis for ARB out of UC Berkeley and UC Davis (“A Low Carbon Fuel Standard for California, Part 1: Technical Analysis,” Farrell and Sperling⁶

⁶ August, 2007, Project Directors, Alexander E. Farrell, UC Berkeley, Daniel Sperling, UC Davis, http://steps.its.ucdavis.edu/publications/2007pubs/stepspubs_its/FarrellSperlingLCFS1.pdf , Attachment 19 FarrellSperlingLCFS1

page 25) recommended using the most recent year before the regulatory development, and specifically not a future year such as 2010. The 2010 baseline is just over 96 gCO₂e/MJ for gasoline and just under that for diesel, and ends at higher carbon intensity at about 86 g CO₂e/MJ in 2020 for gasoline and diesel. If the UC recommendation was used, the end point for LCFS would be 82.9 gCO₂e/MJ. The LCFS draft is almost four percent higher than the endpoint assumed in the UC Berkeley Technical Analysis, meaning that the new draft will only get a nominal six percent LCFS reduction, not 10 percent (without considering the other problems that undermine LCFS reductions). Since carbon content of crude is getting higher, setting a future baseline instead of the normal procedure of using a recent past baseline, builds a starting point into LCFS with higher carbon content, reducing LCFS effectiveness. The purpose of setting a baseline in this case was to reduce emissions from current use. Artificially starting in the future when emissions will be higher, is simply a means of lowering the original goal of 10 percent reduction in carbon content for LCFS. (CBE3)

Response: While we acknowledge that the LCFS regulation has designated 2010 (the first year of the program) as the baseline year, the approach in the regulation achieves the same endpoint that would have been achieved by following the recommendation in the cited UC report, i.e., using the most recent year before the regulatory development to establish a baseline from which reductions are calculated. Executive Order S-01-07, which established the goal to develop an LCFS, was issued in January 2007. Therefore the objective of the regulation is to achieve an overall 10 percent reduction in the carbon intensity of fuels by 2020 from 2006, the first full year preceding the Executive Order. Because the carbon intensity established for the 2010 baseline is essentially equivalent to the baseline in 2006, as explained below, the approved regulation achieves this objective. Consequently, the reduction targets of the LCFS program are not lowered or compromised as suggested by the commenter.

The 2010 baseline carbon intensity values were calculated by CA-GREET version 1.8 b using the most recent GHG emissions data available (year 2006 or earliest available) so that the analysis most accurately reflects recent fuel production in California. The 2010 baseline carbon intensity for gasoline was determined using 10 percent by volume corn ethanol to reflect the expected changes in California reformulated gasoline (CaRFG) formulations between 2006 and 2010. In 2006, CaRFG contained an average of six percent ethanol by volume. However, as a result of the implementation of the Federal Energy Independence and Security Act of 2007 and compliance with the amended CARFG3 regulations, the amount of ethanol in CaRFG is expected to increase to about 10 percent by volume in 2010. It is important to note that in spite of the change in ethanol volume percentages between 2006 and 2010, the calculated gasoline carbon intensity is unchanged since the carbon intensity values for the blending components CARBOB (95.85 gCO₂e/MJ) and ethanol (95.86 gCO₂e/MJ) are practically the same. The diesel baseline carbon intensity is determined using California ultra-low sulfur diesel fuel (ULSD). ULSD formulation is not expected to change between 2006 and 2010, thus the carbon intensity value is also unchanged between 2006 and 2010.

The 2010 baseline carbon intensities for gasoline and diesel fuel used in the regulation are 95.85 gCO₂e/MJ and 94.71 gCO₂e/MJ, respectively. These result in 2020 target carbon intensity values of 86.27 gCO₂e/MJ and 85.24 gCO₂e/MJ, respectively. These values are different from the UC target carbon intensity value of 82.9 gCO₂e/MJ cited by the commenter. The ARB staff's calculated values are a result of a more comprehensive analysis and use of latest available data. On the other hand, the UC analysis was preliminary in nature and used older data. These differences account for the difference in the calculated carbon intensity values.

C-147. Comment: We seek confirmation that while 2010 only requires reporting regulated parties could still realize credits for reductions made in 2010 and bank such credits for future use. (WSPA1)

Response: Under the regulation as adopted, credits cannot start being generated until January 2011. This is because 2010 is a reporting-only year, so regulated parties will not realize credits/debits for fuels supplied in 2010. The purpose of making 2010 a reporting-only year is to test the compliance reporting system for the LCFS and allow stakeholders to become familiar with it. Because there are no mandated standards for 2010, credits may not be generated and banked in 2010.

C-148. Comment: CARB's proposed regulations would establish separate standards for gasoline and diesel fuels. Shell disagrees with this approach and suggests that CARB should instead establish a single standard applicable to both gasoline and diesel fuel that recognizes the efficiency of diesel engines and consequently the overall reduction in greenhouse gas emissions that would come with an increase in the dieselization of the light duty vehicle fleet. As it stands, CARB's regulations do not create any incentive for refiners to produce more diesel fuel. By doing so, we believe that CARB is missing an important opportunity to reduce overall greenhouse gas emissions from motor vehicles. (SHELL)

Response: In Resolution 09-31, the Board found that including an LCFS standard for diesel fuel and its replacements in addition to a standard for gasoline and its replacements is appropriate because including diesel fuel from the beginning will allow for the development of a more robust credit market. Further, the Board found that doing so will provide greater certainty on future expectations. Finally, the Board found that eliminating the diesel element would reduce the LCFS benefits by 20 percent. The Staff Report discusses these in more detail at X-2, X-3, X-5, VI-16, and VI-17.

C-149. Comment: The low carbon fuel standard should be challenging but achievable. Section 2 of the draft outline states that the low carbon fuels standard will require a 10 percent reduction in the full lifecycle intensity of gasoline and separately a 10 percent reduction in the full lifecycle carbon intensity of diesel fuel by 2020.

CARB has not yet conducted a feasibility assessment for such requirements, and thus the achievability of these standards is not known. Earlier in this process, CARB did an assessment of the feasibility of a 10 percent reduction in carbon

intensity but that assessment was conducted on a very different set of assumptions from the ones that are now being considered. There are two significant differences between CARB's earlier evaluation of the technological feasibility and the current draft outline. Firstly, the earlier analysis considered a 10 percent reduction in the carbon intensity of transportation fuels as a whole, while the current draft would impose separate standards on gasoline and diesel. Secondly, the earlier analysis presumed that blending additional ethanol and FAME into fuels would provide a significant proportion of the reduction and this presumption is now being re-examined in light of the land use change issue. (SHELL)

Response: As noted in response to Comment C-145, in Resolution 09-31 the Board determined that the regulation as approved, including its 10 percent carbon-intensity reduction schedule, was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective GHG emission reductions from transportation fuel used in California. The Board also determined that the regulation will encourage early compliance with the requirements. Further, the Board determined that no reasonable alternative considered, such as the one suggested, would be more effective at carrying out the purpose for which the regulation is proposed or would be as effective as and less burdensome to affected private persons and businesses than the regulation.

With regard to the separate standards and compliance schedules for gasoline and diesel, this was addressed in response to Comment C-148.

C-150. Comment: It is essential that the program contain a realistic compliance schedule that is coupled with commercially feasible, proven, and cost-effective compliance options for obligated parties. (CONOCO)

Response: See response to Comment C-149.

Exemptions and Opt-Ins

C-151. Comment: In addition to military vehicles, we wish to add military tactical equipment to the exempt applications, as this must share a common fuel with tactical vehicles consistent with deployment requirements and training realism. We suggest the following addition: (3) Military tactical vehicles, as defined in 13 CCR §1905(a), and Tactical Support Equipment as defined in Title 17 CCR Section 93116.2 (a)(36). (USNAVY1, USNAVY3)

Response: The regulation was modified as requested.

C-152. Comment: Regulated parties should get credit for using renewable fuels in locomotive, aviation and marine fuels. We agree with CARB's decision to exclude aviation, interstate locomotive and marine fuels from the obligation. However, to the extent that the carbon intensity of such fuels is reduced, for

example by blending lower carbon renewable fuels into aviation, interstate locomotive or marine fuels, we believe that credit should be given for this. This approach is consistent with the federal Energy Independence and Security Act, which does not include aviation or marine volumes in the obligation, but provides credits for renewables used in such fuels. (SHELL)

Comment: ARB is proposing that LCFS credits cannot be generated from fuels not subject to the LCFS (e.g. aviation fuels, certain marine fuels). We believe this is not a good policy decision. Fuel providers should be encouraged to look for voluntary actions outside of the regulated scope of the LCFS to generate GHG credits. We recommend ARB allow regulated parties to enter into agreements or protocols with ARB that would encourage technology development through the generation of LCFS credits. For example, this might include a refiner agreeing to use a renewable fuel blend in the ocean going vessels that operate in and out of California, or providing an aviation fuel that uses a renewable feedstock. ARB could use a process similar to the one above for generating early credits or allow for a Memorandum of Understanding under the proposed rules. (WSPA1)

Response: The intent of the LCFS is to reduce the carbon intensity of transportation fuels that are currently regulated by ARB (including some locomotive and marine fuels). By not allowing credits from the reduction of GHG emissions from other sources, the LCFS currently confines providers of transportation fuels to develop alternatives within the regulated transportation fuel sector to reduce the carbon intensity of their fuels. A cap-and-trade program is currently under development, and transportation fuels are scheduled to be incorporated into the cap-and-trade program by 2015. As part of that program's development, fuels that are exempt from the LCFS regulation may be brought into the cap-and-trade program to incentivize GHG reductions from those fuels. See also response to Comment C-107.

C-153. Comment: The LCFS sets forth voluntary opt-in provisions for specific fuels that are presumed to meet the compliance schedules through December 31, 2020. Among those fuels listed is Fossil CNG from North American sources. However, although quite similar, Fossil LNG from the same sources is not on the list. Given that the production of domestic-based LNG for transportation fuel requires liquefaction (rather than compression) and truck delivery to a fueling destination, it does not appear that this variation in process should significantly increase the carbon impact of LNG when compared to domestically-based CNG on a "well-to-wheel" basis. We therefore urge the Board and CARB staff to classify "LNG from domestic sources" on the "compliant fuel" list and provide §95480 status upon rule adoption. Otherwise, an explanation should be provided for why it is not included. (CE1, CE2, CNGVC1, OCTA)

Response: The opt-in provision is available to certain fuels that meet the LCFS standards through 2020. When the regulation was approved on April 23, 2009, the pathway analysis for LNG was not completed and therefore a compliance determination

for LNG was not possible. Therefore, LNG from North American sources is not listed as an opt-in fuel. The Board understands that as pathways for alternative fuels are determined, additional fuels may be found to comply with the 2020 targets. Keeping this in mind, the Board has delegated to the Executive Officer the authority to conduct and complete rulemakings to add to or amend the list of opt-in, low carbon fuels specified in Section 95480.1 (b). Resolution 09-31 at page 16. The analysis of low carbon LNG pathways is underway. The compliant pathways would be added to the opt-in list, as appropriate, in future rulemakings pursuant to the Board's directive.

C-154. Comment: In addition to listing "LNG from domestic sources" as a compliant pathway, it would also be beneficial to both our Industry and CARB if the proposed Final LCFS regulation included blends of fuels, particularly if the fuels involved are already deemed compliant. We would ask that CARB staff include and the Board incorporate the following pathways upon rule adoption: LNG-biomethane blends, CNG-biomethane blends, and CNG-hydrogen blends. (CE1, CE2, CNGVC1, OCTA)

Response: The opt-in list of compliant fuels as published in Section 95480.1 (b) of the LCFS regulation includes, amongst other compliant fuels, Hydrogen blends, Biogas CNG and Biogas LNG. As explained in the previous response, per Resolution 09-31, the Board allows for future additions and amendments to the current list of opt-in fuels. The compliant pathways would be added to the opt-in list, as appropriate, in future rulemakings per the Board's direction. See also response to Comment C-13.

C-155. Comment: Clarify CARB's intent of applying a "LCFS diesel" comparison in the LNG pathway analysis. To date, this comparison has been used by those who either do not understand that the LCFS diesel referenced is a hypothetical or misuses the comparison as a reason to maintain the status quo over implementing alternative fuel truck programs that would increase the use of widely available low carbon fuels. (CE1)

Response: Clarification of the referenced LNG comparison with diesel as requested by the commenter is outlined below:

Under the LCFS regulation, the carbon intensity of alternative fuels would be judged against either the gasoline or diesel carbon intensity requirements, as specified in Section 95483. Typically, gasoline is used in light- and medium- duty vehicles. Therefore, the carbon intensity of an alternative fuel (other than biomass-based diesel) used in light- and medium- duty vehicles is compared to carbon intensity requirements for gasoline. Carbon intensity of fuels not used in light- and medium- duty vehicles is compared to carbon intensity requirements for diesel. Further, the carbon intensity of the alternative fuels is adjusted for efficiencies of fuels relative to the baseline fuel (gasoline and diesel) that the alternative fuel is replacing. Since LNG is primarily used in heavy-duty trucks and natural gas fueled locomotives, carbon intensities of LNG pathways are compared with diesel. Additionally, since in each of these applications LNG is replacing diesel (not gasoline), the fuel efficiency is compared with efficiency of

diesel in the respective application. A detailed discussion of reasoning behind the provisions related to applicable standards for alternative fuels and methodology for calculating credits/deficits is available in Chapter V of the ISOR.

C-156. Comment: WSPA is concerned with the amount of fuel being designated as the volumetric limit for an alternative fuel that is exempted from the program. This seems to be a high volume allowed especially when one considers the anticipated small penetration rate of vehicles utilizing these fuels. We do not support any transportation fuel being exempted from the LCFS regardless of the volume. In addition, the inclusion of LPG as an exempted fuel in relation to the other alternative fuels does not appear to be valid. We request that this provision be deleted. (WSPA1)

Response: The regulation exempts any alternative fuel that is not biomass-based or renewable biomass-based and for which the aggregated volume by all parties for that fuel is less than 420 million mega-Joules per year (3.6 million gasoline gallon equivalent per year compared to the 20 billion gallons of total motor vehicle fuel consumed each year in California). This is intended to exempt research fuels entering the market or very low volume niche fuels. The exemption would allow alternative fuel providers, particularly small-volume producers whose fuels have inherently low carbon intensities, adequate lead-time to develop the technologies necessary to make their fuels viable for future transportation applications.

LPG has been exempt because it neither plays a significant role as a transportation fuel in the current market, nor is anticipated to be a significant contribution to the transportation pool in the 2010 to 2020 timeframe. Published data indicate that propane used in the engine fuels market in California has been relatively flat for the last several years. Modest growth in the forklift market, which is driven by economic growth, has been offset by declines in propane used in on-road vehicles. There have been very few new propane vehicles added in California during this period due to the lack of suitable OEM propane vehicles and certified propane vehicle conversion kits.

C-157. Comment: We recommend removal of the credit generation opt-in provision for specific alternative fuels for the following reasons:

- a. It is premature to presume the fuels listed will have a full fuel-cycle carbon intensity that meets the compliance schedules through 2020. (WSPA1)
- b. This approach does not portray a purported equal or fuel neutral treatment by ARB. Why is ARB treating electricity generators differently than other parties? (WSPA1, Comment 2895)
- c. Further, not requiring all transportation fuels to comply with the LCFS will limit the availability of credits which may be needed to comply with the regulation because there may be several reasons (e.g., AB 118 funding program restrictions or aversion to reporting requirements) that may encourage the opt-in alternative fuel parties to not bother with the program credits and our industry will be unable to comply. (CONOCO, WSPA1)

Response: The specific concerns of the commenter are addressed in the responses below:

- a. The following analysis is provided to demonstrate that the listed fuels under opt-in provision are compliant with 2020 reduction targets: The 2020 target carbon intensities for LCFS fuels substituting for gasoline and diesel are 86.27 gCO₂e/MJ and 85.24 gCO₂e/MJ, respectively. As an example, take a worst case scenario i.e. compliance with the more stringent diesel scenario. For the most carbon intensive pathways for CNG, biogas LNG, electricity and hydrogen production, carbon intensities (adjusted for EER values relative to diesel) are 75.6 gCO₂e/MJ, 31.4 gCO₂e/MJ, 46 gCO₂e/MJ, and 74.8 gCO₂e/MJ (reference: ISOR tables IV-15 and IV-16). Even these values are well below the 2020 target value of 85.24 gCO₂e/MJ for diesel substitutes. There is no reason to believe that future production methods will be more carbon intensive than the pathways under consideration. On the contrary, advancement in vehicle technologies and fuel production methods is expected to lower the carbon intensities for these fuels further in the near future. In fact, alternative production methods available today are already less carbon intensity than the pathways considered in this example. Thus, it is not premature to presume the fuels listed will have a full fuel-cycle carbon intensity that meets the compliance schedules through 2020.
- b. The LCFS is structured to be fuel-neutral. Since certain alternative fuels are already compliant with LCFS carbon intensity requirements through 2020, we did not deem it necessary to burden the providers of these fuels with mandatory regulatory requirements. Rather, they have been provided an opportunity to opt-in to the LCFS program should they choose to generate credits. It should be noted that once they opt -in, they will be subject to the same regulatory requirements as other regulated parties under the LCFS. Thus, there is no basis to the commenter's claim that certain fuels including electricity are treated better than others.
- c. Programs such as AB 118 can be complementary measures that encourage development of low carbon fuels. The commenter's concern that such programs will discourage participation of regulated parties in the LCFS program is not justified. On the contrary, such programs are expected to provide incentives in many situations that will help achieve the goals of the LCFS. We expect that the market would determine a fair economic value for LCFS credits. This would provide incentive to the providers of low-carbon fuels to participate in the LCFS program to generate credits. There is no reason to believe that the opt-in provision will create a lack of credits in the LCFS market.

C-158. Comment: To help maximize the benefits of the LCFS, we recommend that the ARB do everything possible to ensure that the LCFS promotes the cleanest, most sustainable ultra-low carbon fuels like electricity, hydrogen from renewables, even in the early years. Therefore, we request that the ARB either affirmatively include ultralow carbon fuel requirements or ensure sufficient

incentives for innovation and advancement of ultra-low carbon fuels are embedded within the structure of the LCFS regulation. (CPB, ALA5)

Response: Although the federal renewable fuel program (RFS2) uses such an approach, the Board has determined that such an approach will be inconsistent with the "fuel-neutral" treatment of the LCFS. Therefore, no specific requirements for selected fuels are recommended in the regulation. The approach in the regulation is to provide a durable framework that uses market mechanisms to spur the steady introduction of lower carbon fuels. The economic value for LCFS credits is expected to incentivize innovation and development of low carbon fuels. Further, the goals of the LCFS are anticipated to be achieved by a combination of strategies involving lower carbon fuels and more efficient, advanced-technology vehicles. The Board did consider alternatives to the regulation, but found that no other alternative would be more effective at carrying the purpose for which the regulation is proposed, or less burdensome to affected private persons and businesses than the proposed regulation. Resolution 09-31 at page 10.

C-159. Comment: You should include "LNG from domestic sources," biomethane- and hydrogen-natural gas blends, and blends of other very low carbon fuels (e.g., CNG-biomethane, LNG-biomethane, and CNG-hydrogen blends) under §95480.1(b) (opt-in provision) upon adoption. (CE1, CE2, CNGVC1, CNGVC2)

Response: The Board considered this comment and found it unnecessary to incorporate the suggested change into the approved regulation. The purpose of the opt-in provision in §95480.1(b) is to exempt those fuels with carbon intensities that are presumed to be already below the specified 2020 levels and are expected to have those carbon intensities under all expected pathways through 2020. However, for the fuels and pathways covered by this comment, it is not clear at this time that the fuels would have 2020-compliant carbon intensities under all expected pathways. Also, the Board expressly delegated to the Executive Officer the authority to conduct rulemakings to add to or amend the list of opt-in fuels specified in §95480.1(b). Thus, if the Executive Officer determines that domestically-sourced LNG or biomethane and hydrogen-natural gas blends are appropriate for inclusion as opt-in fuels, the Executive Officer has the authority to do so at the appropriate time.

C-160. Comment: The Board should allow the Executive Officer to add fuels to the opt-in provision. In the event that the LNG pathway analysis is not completed in time to be incorporated into the rule, we request that language be added to the regulation allowing the Executive Officer to add additional compliant fuels to the list in section 95480.1(b). The EO already has such authority to make changes to the carbon intensities in the Lookup Tables. The addition of a compliant fuel to the opt-in provision is a pro forma change; any fuel that complies with the LCFS automatically qualifies for the opt-in. Such a change should not require formal rulemaking to amend the rule. (CNGVC1)

Response: As discussed in response to C-159, the Board has expressly delegated authority to the Executive Officer to conduct rulemakings to add to or amend the list of

opt-in fuels specified in section 95480.1(b) (See Resolution 09-31 and H&S §39516). The delegation of such authority can be made through a Board Resolution (e.g., Resolution 09-31), thereby making it unnecessary to incorporate a provision in the regulation itself to provide for such a delegation. We disagree that the addition to or amendment of the list of opt-in fuels in section 95480.1(b) is merely a pro forma change that doesn't require a formal rulemaking. The provision lacks specific criteria for making inclusion into the list a mere pro forma change, and changes made to the list without undergoing a formal rulemaking process would likely be deemed an "underground regulation" in violation of the Administrative Procedure Act (Government Code section 11340 et seq.) and regulations promulgated by the Office of Administrative Law thereto (1 CCR §§1-280).

C-161. Comment: WSPA supports a practical opt-in process that is designed to encourage innovation to produce lower carbon intensity fuels. It should ease the burden on applicants to the extent possible, while providing the ARB with the assurance that accurate values are being generated. (WSPA1)

Response: It appears that the commenter's use of the term "opt-in" refers to the general process of getting a modified or new fuel pathway approved pursuant to section 95486(c) and (d) (i.e., Method 2A or 2B, respectively) rather than the "opt-in" list of fuels specified in section 95480.1(b). The approved regulation provides a practical opt-in process under Method 2A and 2B that would allow regulated parties to obtain approval for modified or new pathways. The acceptance of the proposed pathways is subject to Executive Officer approval under a formal rulemaking process, which helps ensure that only the most scientifically valid and relevant data are used to establish the carbon intensity values for different pathways. This provides a practical approach with flexibility for fuel producers who develop and use different pathways with low carbon intensity values, thus encouraging innovation to produce lower carbon intensity fuels.

See also the response to Comment C-65 for an additional discussion on why the Method 2A and 2B process requires a formal rulemaking.

Definitions

C-162. Comment: The current definition for Biogas is a bit oversimplified and may not cover all of the probable sources of Biogas. We recommend the following definition: Biogas means natural gas that meets the requirements of 13 CCR §2292.5 and is produced from the breakdown of organic material in the absence of oxygen. Biogas is produced in processes including, but not limited to, anaerobic digestion, anaerobic decomposition, and thermo-chemical gasification. These processes are applied to biodegradable biomass materials such as manure, sewage, municipal solid waste, green waste, and energy crops to produce biogas, including landfill gas and digester gas. Because landfill gas and digester gas are both clearly recognized by CARB to be very low carbon intensity sources of biogas fuels, and municipal solid waste and other wastes are likewise recognized by CARB to be very low carbon sources of biogas, we suggest that

these terms be specifically included in the definition of biogas. (WM2, CE1)

Response: The definition of Biogas in Section 95481(a)(5) has been revised to incorporate the language provided by the commenter.

C-163. Comment: If ARB insists on moving forward with a flawed approach that includes more than gasoline during the program's initiation, this section (Section 95480.1) of the draft regulation still does not adequately define exactly what fuels fall under the LCFS, but just lists several transportation fuels (e.g. electricity is not among those listed). WSPA suggests verbiage as follows, which is copied from ARB's Supporting Documentation (3rd and 4th paragraphs on page 4). *For the LCFS, transportation fuel means any fuel used or intended for use as a motor vehicle fuel, other than racing fuel. In addition, transportation fuel includes diesel fuel used or intended for use in nonvehicular sources other than interstate locomotives, aircraft, and marine vessels (except harborcraft).*

The definition of transportation fuels essentially covers the types of use that are subject to ARB's current standards for gasoline and alternative fuels. In California, "motor vehicle" is defined broadly to include off-road construction and farm vehicles. In addition, "transportation fuel" includes diesel fuel used in non-vehicular sources that are currently covered by ARB's standards for ultra-low sulfur diesel fuel (ULSD). This includes all applications other than locomotives that are not subject to ARB's diesel fuel standards for intrastate locomotives, and marine vessels that are not subject to ARB's diesel fuel standards for harborcraft. Since this broader pool of diesel fuel is all currently subject to the same ARB ULSD standards, there has been no need to segregate different batches being used for vehicular versus covered nonvehicular applications. (WSPA1)

Response: The commenter is referring to the definition of transportation fuels contained in an earlier draft of the regulation released on December 1, 2008. The former definition was deemed confusing. We have simplified the definition of transportation fuels contained in section 95481(a)(42) of the regulation to, *"Transportation Fuel" means any fuel used or intended for use as a motor vehicle fuel or for transportation purposes in non-vehicular source.*" Section 95480.1(d) exempts transportation fuels used in five specified applications such as aircraft. The current definition in conjunction with the specific exemption provisions is clear and appropriate. Essentially all fuels excluded under the former draft definition are exempt under the adopted provisions.

C-164. Comment: We remain concerned that the definition of "biogas" is limited to gas derived from anaerobic decomposition, which would exclude gas produced by other processes, such as thermochemical gasification. We urge that thermochemical processes be included in the LCFS definition for "biogas." (CNGVC1)

Response: We agree; the definition of "biogas" in section 95481(a)(5) was modified accordingly and broadened to cover gas produced in processes including, but not

limited to, anaerobic digestion, anaerobic decomposition, and thermo-chemical decomposition.

C-165. Comment: The definition of “alternative fuels” and the exemption for volumes of alternative fuels in the LCFS Applicability of Standards are very problematic, since, for example, most of the hydrogen currently produced in the state is made from fossil fuels at oil refineries. The LCFS justifies this exemption on the basis that it will encourage small producers of alternative fuels. The exemption from the LCFS is intended to allow alternative fuel providers, particularly small volume producers whose fuels have inherently low carbon intensities, adequate lead-time to develop the technologies necessary to make their fuels viable for future transportation applications. In the implementation of the LCFS, the exemption could apply to hydrogen, electricity, liquefied propane gas, and other fuels under research and development. This is not correct in the case of hydrogen, which is not inherently low carbon as described above when produced by fossil fuels. In fact, new oil refinery hydrogen plants are project to emit over 1 million metric tons per year of CO₂. Unfortunately, this exemption doesn’t ban large producers such as oil refineries, which make hydrogen from fossil fuels to use this exemption. This would be easy to fix simply by removing the exemption for fossil fuel generated hydrogen, and for large industrial polluters from using this exemption. Such entities must be held accountable for GHG emissions and local co pollutants caused by the energy-intensive production of fossil-fuel generated hydrogen. (CBE3)

Response: This comment appears to pertain to the “Exemption for Specific Alternative Fuels” in section 95480.1(c)(1). If true, it would appear the commenter misunderstands how this provision works vis-à-vis the rest of the regulation. It is a well-established legal principle that all parts of a regulation must operate and be read together. With this in mind, it can be shown that the commenter’s suggested scenario involving petroleum-based hydrogen simply will not provide the implied advantage to the refiner, as explained below.

When the various provisions of the regulation are read together, it becomes clear that a fuel exempted under section 95480.1(c)(1) cannot be used to generate LCFS credits except under certain circumstances. First, a producer of a fuel like hydrogen must make a choice between being exempted completely from the regulation or opting in (and thereby becoming a regulated party and potentially getting the benefits along with that status). This is because hydrogen is subject to either the exemption in section 95480.1(c)(1) or the opt-in provision in section 95480.1(b)(2). But the same hydrogen cannot be treated under both provisions at the same time, and a regulated party for the hydrogen must make a choice as noted above.

If the regulated party for petroleum-derived hydrogen chooses to opt in and seek LCFS credits, the regulation requires that a fuel pathway for that fuel has already been established, or a new or modified pathway for the fuel has been approved. If there is no such established fuel pathway, and the regulated party does not get approval for a new

or modified pathway, the regulated party would not be able to get LCFS credits for that fuel.

To illustrate this using the suggested scenario, it is true that an oil refiner wishing to produce petroleum-derived hydrogen can get that hydrogen exempted under section 95480.1(c)(1). However, the refiner would not be able to get LCFS credits for that hydrogen without taking additional steps as noted above, including the first step of opting in under section 95480.1(b)(2). This is because the calculation for LCFS credits in section 95485(a)(3)(A) and (B) requires the carbon intensity (CI) for a fuel to be determined by a California-modified GREET pathway (i.e., a CI value is established in Table 6 or 7 in section 95486(b)) or a custom pathway (i.e., a CI value is established pursuant to Method 2A or 2B in section 95486(c) or (d), respectively).

Tables 6 and 7 set forth the CI values for various hydrogen pathways, none of which are based on a petroleum pathway. Instead, the hydrogen CI values shown in those tables are based on hydrogen derived from North American natural gas (see section 95486(b)(1)(I)). Thus, the hypothetical oil refiner in the commenter's scenario would need to get Executive Officer approval for a modified or new pathway governing its petroleum-derived hydrogen (via Method 2A or 2B) in order to get LCFS credits for the hydrogen.

Without LCFS credits, there is little incentive for an oil refiner to invest millions of dollars to produce substantial amounts of hydrogen just to be exempted from the regulation under section 95480.1(c)(1). This is because a fuel that is merely exempted under section 95480.1(c)(1) presumably would have much less market value than the same fuel that has been opted-in and is accompanied by LCFS credits. Regulated parties (e.g., CARBOB producers) would presumably seek out the higher value hydrogen that comes with the LCFS credits because that hydrogen would help the purchasing regulated parties to comply with their LCFS obligations.

With regard to the commenter's suggestion that petroleum-derived hydrogen has a high carbon intensity value, the commenter is missing the point somewhat of the LCFS. The LCFS is not designed to prohibit fuels that are deemed to be "high" in carbon intensity. Nor is the LCFS intended to place a value judgment on the various regulated fuels. The LCFS is simply a market-based framework in which the carbon intensity of the fuels are objectively ranked using the best available science, a declining carbon intensity schedule is set forth for the California fuel pool, and the market then decides what roles the various fuels will play. Thus, whether petroleum-derived hydrogen has a relatively higher or lower carbon intensity is beside the point – both high and low carbon intensity hydrogen can play a role in the California transportation market. But the role they play depends on what value the market places on such hydrogen. Even relatively higher carbon-intensity hydrogen may still have value to a regulated party depending on the circumstances (e.g., if the supply of such hydrogen is much more certain than other sources of hydrogen).

Based on the above reasons, it is clear that the LCFS regulation, as adopted, holds regulated parties for hydrogen and other fuels accountable for the fuels' carbon intensity by linking the exemptions and opt-in provisions to the carbon intensity requirements and credit provisions.

Regulated Party

C-166. Comment: Section 95423 of the draft regulations provides that on each occasion before gasoline or diesel is transferred from distribution terminals, when any person transfers custody or title of gasoline or diesel (i.e., the transferor), the recipient of the gasoline or diesel (i.e., the transferee) assumes the LCFS compliance obligation, and becomes the regulated party under the regulations, unless the parties contractually agree to leave the obligation with the transferor. Moving the obligation downstream of the refiner/importer as CARB proposes aligns the obligation with the ability of the regulated party to take action to comply. It is the downstream oxygenate or biodiesel blender, not the refiner/importer, that has the ability to decide what type of ethanol or biodiesel will be blended into gasoline or diesel, and thus under the low carbon fuel standard, the obligation should be placed on the oxygenate or biodiesel blender.

Although CARB's proposal for establishing the obligated party aligns the obligation with the ability to take action to comply, we believe that CARB needs to provide additional clarification to ensure that this approach is workable in practice. The proposed regulations specify that the transferor is required to provide to the transferee the carbon intensity of the fuel transferred. We believe that it is critical that the requirements do not interfere with the fungible shipment of gasoline and diesel fuels. Thus, we believe that CARB should clarify that the rule is not intended to require gasoline or diesel fuels to be segregated on the basis of their carbon intensity. Segregation on the basis of carbon intensity is not necessary to achieve the objectives of this program. Even if fuels are not segregated on the basis of their carbon intensity, transferors can advise transferees of the carbon intensity of the fuels supplied and that can serve as the basis for compliance for the transferees. (SHELL)

Response: This comment refers to an earlier draft of the LCFS regulation released for public comments in October 2008. Per the current provisions in the regulation, regulated party for gasoline and diesel are the producers or importers of the fuel or blendstock, or certain recipients, as specified in the regulation. Our intent here is to keep the number of regulated parties to a minimum, at the same time allowing flexibility for transfer of obligation by contracts.

In case of transfer of compliance obligation, the transferee is required to provide a product transfer document stating the volume and average carbon intensity of the transferred fuel or blendstock. This is to ensure that the recipient of the compliance obligation has the necessary information to fulfill the reporting requirements of the regulation. For cases involving sale of finished fuels, the carbon intensity of finished

fuel should be provided; in case of blendstocks, the carbon intensity of blendstocks sold should be provided in the transfer document. In general, if more than one type of fuel or blendstock is sold, the carbon intensity and volume of each batch must be provided. To meet the reporting requirements, the fuels do not need to be physically segregated. However, carbon intensity of each batch of fuel or blendstock sold must be documented since this is the only way to ensure proper accounting at the end of the year.

C-167. Comment: BP believes that it is important that the regulation be written in a way that minimizes the amount of monitored transactions while still adequately capturing all regulated fuel volumes. BP's preferred option would be for the point of regulation for CARBOB and finished fuels to be at the location of manufacture or import. This point of regulation is consistent with both the Federal Renewable Fuel Standard and the California RFG program. It also enhances enforcement by providing certainty in terms of the identity of the regulated party. Producers that buy and sell fuels to other regulated parties can agree to transfer LCFS credits through contractual relationships to keep compliance obligations in line with blending opportunities. (BP)

Response: The regulation as approved follows a similar approach - the producers and importers of CARBOB and gasoline are identified as the regulated party initially. While the obligation transfers automatically to another producer or importer with title, for sale to other downstream entities the compliance obligation is retained by the transferor i.e. kept upstream. The intent here is to keep the compliance obligation with a smaller number of upstream entities. This also minimizes the amount of monitored transactions as suggested by the commenter. While keeping these considerations in mind, it is also ARB's intent to allow flexibility for the participating entities in the LCFS fuel market. Therefore, transfer of compliance obligation is allowed between certain consenting parties by written contract. This approach allows small businesses that blend clean fuels opportunity to generate credits if they are willing to take on obligations that come with regulatory requirements. It should be noted that trading of credits between regulated parties is allowed in the regulation so that option is always available to consenting parties. However, while ARB considered the alternative approach suggested by the commenter to restrict the transfers of compliance obligation and allow only credit transfers, this was not allowed as this would make the program more restrictive and less flexible.

C-168. Comment: ConocoPhillips believes that a producer or importer of "finished fuel" should be able to retain the compliance obligation if the "finished fuel" from the production or import facility does or does not contain a renewable fuel with lower carbon intensity than the base fuel. The carbon intensity of the renewable fraction should be based upon the lifecycle analysis for the individual renewable fuel pathway (examples include renewable gasoline, renewable diesel, etc.). This provision is needed to assure that research in advanced renewable fuels continues and that those fuels are suitably deployed in California. (CONOCO)

Comment: WSPA recommends there be no separate treatment of parties that are producers or importers and parties that are non-producers or non-importers and that ARB treats all parties as producers or importers. As with the transfer to a producer/importer the obligation should transfer to nonproducer/non-importer unless the producer/importer agrees to retain the obligation via written notification. Moving the obligation downstream of the production/import facility if the fuel transfers title aligns the obligation with the ability of the regulated party to take action to comply. (WSPA1)

Comment: Pg14. Section 95424 (a)(2)(B)(4) As with the transfer to a producer/importer the obligation should transfer unless the producer/importer agrees to retain the obligation via written notification. (WSPA1)

Response: The provisions of the regulation allow this. See response to Comment C-167.

C-169. Comment: If ARB chooses to retain the distinction between producers/importers and non-producer/nonimporter, then WSPA suggests as an alternative that ARB revise the definition of producer and production facility in the LCFS regulations as described below. “Producer” means any person who owns, leases, operates, controls or supervises a California production facility.

“Production facility” means a facility in California at which gasoline, diesel or CARBOB is produced or at which biodiesel is added to diesel. While these changes in definitions may meet the objective it is not our preferred approach as we believe this may lead to confusion resulting from different definitions for producer and production facility in the proposed LCFS regulations and existing CBG regulations. (WSPA1)

Response: While the commenter’s suggestion may work for gasoline and diesel producers, the LCFS regulation is not limited to gasoline and diesel producers. Instead, the scope of the LCFS is broad and covers producers of gasoline, diesel, alternative liquid fuels that may be blended with gasoline or diesel (e.g., biodiesel, renewable diesel), and other alternative transportation fuels (e.g., hydrogen, electricity, CNG, LNG, biogas, etc.). Thus, the definitions of “producer” and “production facility” were developed to encompass not only producers of gasoline and diesel but also providers of the other alternative fuels regulated under the LCFS. The definition suggested by the commenter will not work for the regulation as it does not address providers of all regulated fuels.

C-170. Comment: The December 2008 draft regulations stated that on each occasion before gasoline or diesel is transferred from distribution terminals, when any person transfers custody or title of gasoline or diesel (i.e., the transferor), the recipient of the gasoline or diesel (i.e., the transferee) assumes the LCFS compliance obligation, and becomes the regulated party under the regulations, unless the parties contractually agree to leave the obligation with the transferor.

Shell supports the approach taken in the December 2008 draft, and urges CARB to return to this approach. Shell requests that CARB align the gasoline and diesel fuel compliance obligation with the entity that has final control of the fuel before it leaves the terminal, regardless of the individual. There should be no separate treatment of parties that are producers or importers and parties that are non-producers or non-importers. Rather, the regulations should treat all parties the same as the way that CARB proposes to treat producers and importers. As with the transfer to a producer/importer the obligation should transfer to non-producer/non-importer unless the producer/importer agrees to retain the obligation via written notification. Moving the obligation downstream of the production/import facility if the fuel transfers title aligns the obligation with the ability of the regulated party to take action to comply. (SHELL)

Comment: Valero believes that the LCFS regulations must create a level playing field for obtaining and generating LCFS credits among all parties that have control over what is added to CARB gasoline, CARBOB and CARB diesel. The LCFS regulations must create a level playing field between obligated parties and oxygenate and biodiesel producers. Specifically, the automatic transfer of the LCFS obligation from the seller to the buyer for CARB gasoline, CARBOB or CARB Diesel, before loaded into trucks at the truck rack, should apply to all buyers not just those that are refiners and importers. The party that has title to the fuel at the truck rack is the party that controls what, if any, biofuel is added. The LCFS regulations will be more workable if all parties that have title to fuel at or above the truck rack, have a direct obligation rather than an indirect incentive to blend biofuels. (VALERO)

Response: The current approach keeps the majority of compliance obligations with producers and importers as this allows for effective enforcement taking into consideration the availability of carbon intensity data and the extent to which the data are verifiable. Currently seven large oil companies supply about 90 percent of the gasoline sold in California. Producers and importers are already subject to CaRFG3 regulation and are also considered to be the regulated parties for the federal Renewable Fuel Standard (RFS2). Therefore, it is logical to make them the regulated parties for LCFS as well. It should be noted that the regulation allows flexibility for entities participating in the LCFS program by allowing transfer of obligation with transfer of ownership if mutually agreed by the parties in a contract. For the majority of the transportation fuel in California, producers and importers retain control of the ownership throughout blending and distribution. In the instance where a producer or importer transfers ownership of the fuel, the LCFS obligation can also be transferred with a written contract between the trading parties.

C-171. Comment: From our read of the latest draft it appears that when a regulated party transfers ownership to a party that is not a producer or importer, then the default case is that the transferor remains the regulated party (95484(a)(1)(B)(4)). This is a change from the December draft and ConocoPhillips questions the reasoning for this change. ConocoPhillips believes

the point of compliance should be where parties have control over the fuel at the point of delivery to the consuming marketplace. Refiners or importers of the fuel who do not retain title when it is blended with renewable fuel downstream, have limited, if any, control over what the downstream party will chose to blend. The downstream party may make choices based on the lowest cost option versus what is needed to meet the California LCFS goals. (CONOCO)

Comment: Section 95424. Requirements for Regulated Parties-Regulated Parties/Point of Regulation: WSPA believes the LCFS regulations must create a level playing field between obligated parties and oxygenate and biodiesel producers. In addition, the LCFS regulations should not conflict with the U.S. EPA RFS regulations if possible. WSPA requests the proposed regulations should be changed so the LCFS obligation moves with title transfer of oxygenates and biodiesel if it has not already been blended into gasoline or diesel. This would be similar to the U.S. EPA RFS program where the RINs are attached to the renewable fuel until an obligated party or a oxygenate blender or a biodiesel blender takes title of the renewable fuel. The U.S. EPA had several reasons for setting up the RFS program in this manner, which are discussed in the preamble of the proposed rulemaking (Fed. Reg. Vol. 71, #184) of the RFS regulations. This change would directly encourage the purchase of low carbon fuels and discourage the purchase of high carbon fuels by the obligated parties and make the LCFS regulations more workable. (WSPA1)

Response: The regulation does not subject refiners or importers to liability for fuel added downstream over which they do not have control. Per the regulation as approved, where additional renewable fuel is blended with finished fuel (i.e. LCFS compliant gasoline or diesel), the producer or importer of the added fuel or blendstock becomes a regulated party under the LCFS. This person or entity is responsible for meeting the regulatory requirements for the additional renewable fuel that is blended into the finished fuel.

C-172. Comment: The sellers of oxygenates and biodiesel should not be allowed to retain the LCFS obligation at their discretion. This is in direct conflict with how the U.S. EPA set up the RFS program. We believe that the same reasons the U.S. EPA had for the automatically transfer of RINs in the RFS program should equally apply to the LCFS program. (VALERO)

Comment: Section 95484(a)(1)(C)(2) allows a supplier of oxygenate to be able to retain the compliance obligation. ConocoPhillips recommends that this section be removed and the carbon intensity associated with the oxygenate be transferred (by default) along with the oxygenate consistent with federal approaches in the RFS programs. (CONOCO)

Response: While both RFS and LCFS regulate renewable fuels, the two regulations have a number of differences in their structure and approach. Renewable fuels under RFS have to meet volumetric mandates; on the other hand, LCFS is structured as a

performance based regulation. Therefore, while it may be so desired by the fuel suppliers, it is not always effective to mimic the provisions of RFS for regulated parties under the LCFS. For the reasons explained in our earlier responses to Comments C-167 and C-170, it is preferred to place the LCFS compliance obligation on upstream entities rather than downstream distributors. As noted earlier, the regulation does allow flexibility for entities participating in the LCFS program for transfer of compliance obligation with the title for the fuel if mutually agreed by the parties in a contract.

C-173. Comment: Section 95484(a)(1)(C)(2) allows a supplier of oxygenate to be able to retain the compliance obligation. One potential outcome, if this were allowed, could be for an oxygenate producer to sell the oxygenate to a CARBOB producer or importer, keep the “credit” and then either sell that “credit” to a party other than the one that purchased the oxygenate or who supplied the CARBOB. Even of greater concern would be if the oxygenate producer retained associated “credits” for purposes of either raising “credit” value or demand for oxygenate product. (CONOCO)

Response: The Executive Order S-01-07 that established the goal of developing an LCFS specifies that the regulation may be met through market-based methods by which providers exceeding the performance required by an LCFS shall receive credits that may be applied to future obligations or traded to providers not meeting the LCFS. Keeping in line with this specification, the regulation as approved allows the oxygenate producers (and other regulated parties) to sell generated credits to any regulated party that is dealing with a shortfall. Restricting credit trading as suggested by the commenter would be contrary to the free market approach in the LCFS which is critical to the success of the program.

C-174. Comment: The obligated refiner or importer incurs an obligation for the amount of CARBOB that they produced. However, section 3.2.b. appears to also impose an obligation on downstream parties that acquire the CARBOB from the obligated refiner. We urge CARB not to pursue this approach as it imposes two obligations on the same CARBOB. We recommend that section 3.2.b. be eliminated since the same volume of CARBOB would already be regulated under section 3.2.a. We have the same concerns with sections 3.2.c. and 3.2.d. pertaining to diesel fuel. If both are retained, the same volume of diesel will incur two obligations. We recommend that section 3.2.d. be eliminated. We generally believe that CARB should take the same approach towards the other fuels listed in section 3.2 (i.e., natural gas, propane, electricity, and hydrogen). That is, the obligated party should be the producer or importer of the fuel, and the obligation should be based on the volume used as road transportation fuels. The obligated party should be required to keep records and report to CARB the volumes of fuels produced that are in fact used in road transportation fuel. Investment in distribution and fueling infrastructure will be needed in order to provide these fuels to consumers. By requiring the obligated party to demonstrate to CARB the volumes of such fuel used for road transport CARB will provide the market

incentive, through LCFS credit generation, for the development of this distribution and fueling infrastructure. (SHELL)

Response: These comments pertain to an earlier draft of LCFS concept outline released in March 2008 for public comments. The current regulation as approved takes care of the issues raised by the commenter.

C-175. Comment: Although the intent of the rulemaking, as described by CARB, is to target upstream entities as the responsible parties for compliance, the drafting of the rule is often vague, leading to the potential that responsibility could be passed on to other parties, such as OCTA, not originally contemplated by the rule. For instance, in the case of compressed natural gas (CNG), the proposed rule states that the owner of the fueling equipment can be the regulated party. At OCTA there is a lease agreement for such fueling equipment. There is concern, therefore, that OCTA as a lessee could be held responsible for meeting the requirements of this rule. More clarification is needed to ensure that through such lease agreements, responsibility is not passed to unintended parties. The same concern exists in the case of liquefied natural gas (LNG), where the rule states that the responsible party is the owner of the fuel when it is transferred to a fueling tank. This could create a situation where, through contractual terms, the actual fuel provider could pass on responsibility for compliance to unintended parties by including a freight on board (FOB) shipping term in the contract. In cases where a FOB term is included, ownership of the fuel is passed to the recipient from the fuel provider when the fuel is loaded on the truck at the LNG production facility. This could lead to a situation where the intended regulatory entity could escape liability by passing on responsibility for compliance to a party with limited means of fulfilling the regulatory requirements. These concerns also will carryover as transit agencies begin to explore the use of hydrogen as fuel. According to the proposed rule, the regulated entity is the owner of the fuel as it enters the vehicle. These additional liabilities will force transit agencies to be more cautious in the use of hydrogen, thereby potentially delaying exploration of such alternative fuels. (OCTA)

Response: Under the provisions of the regulation as approved, transit agencies would not be burdened with additional liabilities for supplying hydrogen, hydrogen blends, biogas CNG, and biogas LNG. These fuels are opt-in fuels. Transit agencies supplying these fuels would only become regulated if they want to generate credits. Compliance with regulatory requirements for such entities is not mandated unless they themselves opt-into the program. Furthermore, with respect to biogas CNG blended with fossil CNG, the producer or importer of biogas CNG is the regulated party. The same provision exists for biogas LNG blended with fossil LNG. Therefore, the Orange County Transit Agency (OCTA) or other transit agencies would not be a regulated party for biogas portions of such blended fuels and thus would not be liable to comply with the regulatory requirements.

With regards to fossil CNG and fossil LNG, the regulation specifies the criteria for identification of regulated party as: for fossil CNG, the owner of dispensing equipment is the regulated party; for fossil LNG, the person or entity that owns title to the LNG when it is transferred to the fuel dispensing equipment in California is the regulated party. OCTA or other transit agencies could potentially qualify as regulated party for fossil CNG and fossil LNG if they meet the specified conditions in the regulation. ARB believes that it is the responsibility of the transit agency to ensure that their business contracts with producers of the fuels and/or owners of the fuel dispensing stations are written in a way so as to avoid the unwanted compliance obligation. Changing the regulation to avoid this potential compliance obligation is not justified and interferes with the fair and neutral treatment of the regulation.

C-176. Comment: The point of compliance for natural gas and electricity lies with the entity responsible for the quality of the fuel. Within the liquid fuel market everyone shares in the responsibility for the quality of the fuel as it is moved downstream of the production or import facility. As such it is unclear where ARB intends to enforce the LCFS on such natural gas and electric fuel providers. ARB should be more specific on where exactly ARB would intend to enforce the LCFS on such fuel providers. (WSPA1)

Response: The commenter appears to be referring to language (viz. “point of compliance”) used in earlier draft versions of the regulation and is no longer used in the approved regulation. The regulation, as approved, clearly designates which entities in the fuel supply chains are obligated to demonstrate compliance with the LCFS. These entities are referred to as “regulated parties” and are responsible for the fuel and for reporting fuel information to the Board. The regulated parties for natural gas and electricity are identified in the approved regulation under section 95484(a)(5) and (6), respectively.

With regard to compressed and liquefied natural gas derived from petroleum sources (fossil CNG and fossil LNG, respectively), the regulated party for fossil CNG will generally be the utility company, energy service provider, or other entity that owns the fuel dispensing equipment; for fossil LNG, it is generally the entity that owns the fuel when it is transferred to the fuel dispensing equipment in California. For other gaseous fuels such as biogas/biomethane, the regulated party will generally be the person who produces the fuel and supplies it for vehicular use. And for electricity, the regulated party can be the load serving entity (LSE) supplying the electricity to the vehicle, the electricity services supplier, the owner and operator of the electric-charging equipment, or the owner of a home with electric vehicle charging equipment, depending on the circumstances as provided in section 95484(a)(6).

C-177. Comment: “Regulated party” means a person who is subject to the LCFS pursuant to section 95424(a), and must meet the low carbon fuel standards in section 95422. Section 95424 defines the regulated party for an oxygenate (e.g. ethanol) as the producer or importer of the product. Therefore they appear to be subject to the standards in 95422. Is this understanding correct? (WSPA1)

Response: This comment refers to provisions in an earlier draft of the regulation released for public comments in January 2009. This comment would be addressed per the provisions of the approved regulation as follows:

"Regulated Party" is defined in section 95481 as: *"Regulated Party" means a person who, pursuant to section 95484(a), must meet the average carbon intensity requirements in section 95482 or 95483.* Section 95484 (a) in the regulation specifies the criteria under which a person would be deemed a regulated party and if/how the responsibility of complying with the regulation can be transferred. Briefly, the regulated party for oxygenate (e.g. ethanol) added to CARBOB is the producer or importer of the oxygenate. If a regulated party transfers ownership of the oxygenate before it has been blended with CARBOB, the recipient of the ownership becomes the regulated party unless the transferee elects to retain the compliance obligation. The person who is the regulated party for oxygenate is responsible for all compliance obligations identified in the regulation. Oxygenates that are blended with CARBOB are subject to gasoline carbon intensity requirements. Therefore, the regulated party must use the gasoline standards in section 95482.

C-178. Comment: ADM recommends defining proponent-regulated party in the California LCFS regulation. This term is first used in Section 95426, Page 37. A regulated party is defined on page 15 but CARB then states that a proponent regulated party in Method 2A may request approval for customizing look-up table values. A clear definition of proponent regulated party is needed to ensure clarity. (ADM)

Response: This comment refers to an earlier draft of the LCFS regulation. The regulation approved by the Board on April 23, 2009 does not contain the term "proponent regulated party". The point made by the commenter stands mute since the definition of a term not used in the regulation is unnecessary.

C-179. Comment: An initial concern I have is an acknowledgement that downstream retailers responsible for distribution of transportation fuel may be held responsible for carbon intensity of fuels they dispense and thereby be subject to fines and other enforcement mechanisms. Additionally, I have concerns that holding retailers (whom may be unable to afford the purchase of credits) responsible for meeting the LCFS will force many small businesses to close rather than be subject to ARB fines. (CSC)

Response: The regulation is not expected to affect small businesses because, for gasoline and diesel, the regulation does not apply to retailers, but instead it applies primarily to producers and importers (e.g. refiners, utilities, etc.). In general, the compliance obligation is designed to remain with the producer/importer rather than retailers. The regulation does provide for retailers to choose to have the compliance obligation by contract or other agreement.

C-180. Comment: Producers are best positioned to determine the carbon intensity of the low carbon fuels they produce and to provide an initial demonstration of the delivery methods comprising the physical pathway by which their fuel can reach California. ARB should consider adopting a registration program for producers of renewable fuel similar to the registration program under § 80.1150 of the Federal RFS program. An element of the registration would be certification of the carbon intensity of the fuel produced at the production facility and the physical pathway for that facility. A listing of registered producers and their production facilities and pathways could be maintained on the ARB website and associated with the ARB carbon intensity look-up table. This public information would facilitate sourcing of biofuels/blend stocks. A registration program could similarly be developed for importers of fuel into California. The importers are best positioned to satisfy the physical pathway requirements defined in Section 95484(d)(2). Similarly, registered importers could be listed in the ARB website providing information to parties requiring low carbon fuels/blend stocks. (WSPA1)

Response: Staff is in the process of developing a system for validating physical pathway evidence for transportation fuels produced outside of California. This will allow producers of alternative fuels to prequalify the physical pathway and carbon intensity of their alternative fuels and thus facilitate the sale of their fuels to regulated parties.

Energy Efficiency Ratios (EER)

C-181. Comment: The program's inclusion of vehicle efficiency factors has the potential to significantly dilute the effort to reduce carbon from transportation fuels. This effect is well illustrated through the interaction that occurs between the proposed low carbon fuel regulation and vehicle efficiency regulations. These interactions introduce the possibility of double counting emission reductions, which would undermine incentives to introduce lower carbon fuels. In the statewide scoping plan for greenhouse gases, vehicle efficiency regulations and the low carbon fuel standard are two of the largest programs based on the forecast tonnage of emission reductions. This means that avoiding double counting is critical for state to meet its overall emission reduction goals in the near term. At least as important, and perhaps more so, we are wary of the possibility that interactions between the programs could thwart the move to lower carbon fuels over the long term. (AAM)

Response: The inclusion of the EER recognizes that some fuels have lower carbon emissions per mile, and inclusion of the EER in the LCFS will provide an incentive to use these lower per mile carbon-intensity fuels. The ARB staff will monitor very closely the compliance progress for both the fuel economy regulations (Pavley regulations) and the LCFS, and will assess the extent to which double crediting of emissions reductions under the two regulations is likely to be an issue. Also, the Pavley regulations are scheduled to be revisited which will provide an opportunity to remove conflicts between the two regulations. Staff will make necessary changes to the LCFS to complete the harmonization between the two regulations.

C-182. Comment: EERs also introduce thorny analytical issues concerning the relative efficiencies of various future vehicle powertrain technologies, since efficiency differentials and uncertainties can be fairly large compared to California's 10 percent carbon intensity reduction goal for 2020. There is also a fundamental question concerning whether a certain fuel uniquely enables a more efficient powertrain design, and therefore should get EER credit, or whether the more efficient powertrain could also be used with other fuels. (AAM)

Response: The staff agrees that there can be some variation in efficiency from vehicle to vehicle, and some uncertainties associated with calculating average efficiencies for groups of vehicles or fuels. However, clear trends in vehicle efficiencies and average differences between different fuels are clearly discernable, and it is these differences that the staff is capturing with its EER estimates. What's important is that increased (or decreased) fuel economy is recognized in calculating the per mile carbon emissions when the fuel or vehicle is used, and the staff's use of the EER accomplishes this.

C-183. Comment: The EER tool raises many potential issues. This is why we urge the state to use them sparingly and conservatively to prevent EERs from dominating the program and as a result strongly favoring one fuel or technology over another, or to drop the EER tool altogether. One of the key benefits of the low carbon fuel concept is its ability to let the market operate freely, which will happen only if the program provides fuel and technology neutrality. We believe such neutrality is also needed for making the program sustainable and effective. (AAM)

Response: The use of the EER places all fuels and vehicles on a common basis by allowing the carbon emissions to be calculated on a per mile basis, which is the best indicator of a fuel's total lifecycle emissions and global warming potential. This provides the fuel and technology neutrality and sustainability that is needed, which will also allow the market to operate more efficiently.

C-184. Comment: The proposed Energy Economy Ratio (EER) value for compressed natural gas (CNG) in heavy-duty applications is based on a single advanced technology engine meeting ARB's 2010 emissions standards. As noted in the staff report, this engine has less of a fuel penalty relative to diesel than most of the current CNG fleet. While this engine technology is expected to be implemented to some extent in the future, the proposed EER value will be applied to the current vehicle fleet that does not include this technology. The EER for heavy-duty CNG in this rulemaking should be based on the current vehicle fleet; to the extent that more efficient advanced technologies are implemented the EER value can be updated, perhaps as part of the Program Reviews. Establishing an overly optimistic EER for the existing heavy-duty CNG fleet sets up a mechanism in which credits can be generated that are not real. (CHEVRON1)

Response: Today, in-use vehicles with CNG engines represent less than 0.1 percent of the heavy-duty vehicle fleet, as shown in Appendix E of the ISOR. Even if we determined an EER value for this quantity of vehicles and adjusted the carbon intensity value for the CNG supplied to this existing fleet, we would not change appreciably the credits or debits available from the fueling of these in-use CNG vehicles. This is because the maximum contribution to attainment of the required 10 percent reduction from these in-use CNG vehicles is 0.07 percent, leaving 9.93 percent that would need to be obtained from other options.

Starting with the 2010 model year, the only type of heavy-duty CNG engine that may be introduced into the state is the advanced CNG engine mentioned in the comment and used by staff to establish the EER value. Because of this, all future growth in CNG vehicles will be with the 2010 advanced technology CNG engine or its successors. The most optimistic estimate for penetration of CNG vehicles into the heavy-duty fleet is for them to be 3 percent of the heavy-duty fleet by 2020 (ISOR, App. E at E-12). Of this number, over 2.9 percent will have to be the advanced CNG engines.

Based on the above reasons, the EER in the approved regulation is not overly optimistic but represents the correct number for CNG fleet growth and existence in 2020. To ensure that the regulation continues to reflect the most current information, in Resolution 09-31 the Board directed the Executive Officer to re-evaluate and update, if appropriate, the EER for heavy-duty CNG vehicles as soon as practical through formal rulemakings.

C-185. Comment: We do have some areas of concern that we would like to address with staff in the interim and also meet with you before the next hearing. Someone has to do the EER values that were given to us, which we don't think are fair. Not sure if this warrants a response, other than the staff disagrees and does not believe that the EERs are unfair. (CE4)

Comment: With regard to diesel used in heavy-duty application, CHOREN recommends that the LCFS allow for the possibility that some renewable diesel fuels are more efficient than the conventional diesel they are displacing. The LCFS currently assigns biomass based diesel blends an EER value of 1.0 as compared to conventional diesel, which may be an adequate assumption for most biomass-based diesels. However, we encourage CARB to review the attached study of gas to liquids (GTL) synthetic fuels (chemically nearly identical to BTL synthetic fuels), which notes that synthetic fuels have an additional 2-3 percent efficiency advantage over conventional diesel. This is a significant efficiency difference that also should be accounted for. (CHOREN)

Response: The staff will review and analyze the available and future data on fuel economy for biomass-based diesel and gas-to-liquids synthetic fuels, and make any necessary changes to the EER for these fuels. This will be done as appropriate.

C-186. Comment: In Section 95425 of the Regulation and in Table 7 - EER Values for

Fuels. WM has had several discussions with CARB staff on this topic and we remain concerned about the single energy economy ratio (EER) of 0.90 for heavy-duty CNG and LNG ICEVs. Natural gas engine manufacturers have been working continuously for the past decade to improve the thermal efficiency of their engines and have made significant improvements over the past five years. Today's spark-ignited natural gas engines still experience a small thermal efficiency penalty (2 percent to 6 percent) compared to their diesel counterparts, while today's compression ignition natural gas engines are at parity with diesel thermal efficiency. WM recommends that, given these current thermal efficiency comparisons, CARB should set the EER for CNG and LNG engines at a minimum of 0.95, if not at 1.0 given the latest natural gas engines that are now comparable to diesel cycle efficiency. A viable alternative would be to introduce separate EERs for spark-ignited and compression ignition natural gas engines. Either way, WM respectfully requests that CARB staff carefully review the latest certification data for heavy-duty natural gas engines to determine the most correct EER values for each current technology. (WM2)

Comment: There is, however, one outstanding issue that relates to the low carbon fuel standards, and that is the energy efficiency ratio. And why this is an issue for heavy-duty truckers is that they're looking at what you're doing today as a market signal, and they're going to start making purchase decisions based on this very important market signal. Heavy-duty trucks consume vast amounts of fuel as compared to passenger cars. Because of that, and the EER that's designated for heavy-duty natural gas vehicles of heavy-duty natural gas vehicles are penalized. And when you're burning 20,000 gallons of fuel per year, if you're not being attributed the efficiency that the engines have demonstrated in CARB and EPA testing, and as their certificates demonstrate, it represents a negative market signal to a purchase decision that could be made by someone in their efforts to achieve the low carbon fuels that we're all trying to seek here. So with that, I'd like to reiterate that we would like to see either two EERs for heavy-duty natural gas vehicles or a blended EER that accommodates both spark-ignited and compression-ignition engines. (WIINC)

Comment: Current "Compressed or Liquefied Natural Gas Used in a Heavy-Duty Spark Ignited or Compression Ignition Engine" EER value only reflects a "spark-ignited" EER value, staff's own data shows "compression ignition" EER value equal to diesel, EER values can make or break low carbon fuel performance, Staff proposal unfairly penalizes efficient natural gas engines manufactured by Westport (which ironically should receive incentives under the LCFS).

We Recommend:

- A. Assign a separate EER value to spark-ignited engines and a separate EER value to compression ignition engines that is reflective of each engine's performance; or,
- B. Assign a blended EER value that reflects both spark-ignited engine and

compression ignition engine performance (based on the data) to more accurately reflect the "Compressed or Liquefied Natural Gas Used in a Heavy-Duty Spark Ignited or Compression Ignition Engine" EER category. (CE2)

Comment: One thing I'd like to respond is the EER is incredibly important for us. And I'll tell you why. It's not the issue of whether or not a dealer goes or a purchaser goes to the dealer and asks what their fuel economy is. It's how decision makers [and] policy makers use how that EER in determining what vehicles they fund. And we've seen it already with the pathway comparison of the draft pathway comparison, where staff had put in a low carbon fuel diesel, that actually does not, in my view, exist yet. And that has been used by the Port of Long Beach to marginalize the benefits of liquefied natural gas in trucking. So that's the policy point that we're trying to make. Second, we have data that shows equal efficiency for the compression ignition. And so we think that that should be accounted for. And because the rule only calls for one EER value, the compression-ignition engine and the spark-ignited engine should be blended.

My final point is that I think that there's also a concern about using -- or compensating for legacy fleets in this issue. I think it's a really bad idea to start accounting for legacy fleets when you're accounting for an EER, because then you have to look at the gasoline and diesel legacy fleets. And if you're not too careful Canadian oil sand oil may qualify under the low carbon fueled standard because of the aging diesel and gasoline fleets out there. So we're asking for fairness. And I really appreciate -- that said, I really appreciate what staff has done. I think staff has done a marvelous job and we're completely supportive of this low carbon fuel standard. (CE3)

Comment: Inaccurate Energy Economy Ratio for natural gas heavy-duty engines. Section 95485(b) identifies an Energy Economy Ratio (EER) of 0.9 for heavy-duty natural gas engines. More specifically, in Table ES-7, the EER is for "Compressed or Liquefied Natural Gas Used in a Heavy-Duty spark-Ignited or Compression Ignition Engine." The staff used engine certification data submitted to the ARB to determine the EER for this category, and that data shows that while spark-ignited engines have an EER of ~0.9, the EER for compression ignition engines is equal to the EER for diesel. In other words, the proposed EER of 0.9 takes into account only the results for spark-ignited engines and ignore the results for compression ignition engines. The difference between 0.9 and 1.0 is not insignificant once it is applied to the credit calculator proposed in the regulation. Failure to recognize the 1.0 EER for compression ignition engines will deprive the owners of those engines of credits they deserve and undercount emission reductions that are of value to the ARB in implementing the LCFS and AB 32. It will also create an unfair disincentive for fleet owners to invest in the more efficient compression ignition engine, which is counter to the state's interests. (1652) (CNGVC1)

Comment: We urge the Board to establish separate EERs for spark-ignited and

compression ignition engines. We believe this request is achievable and will result in the most accurate EERs. The Coalition will work with staff to establish a process to ensure accurate accounting of the use of LNG in each type of engine. (CNGVC1)

Comment: As an alternative to the current single EER of 0.9, if the Board decides not to establish separate values, we would ask the Board to apply an EER that blends the values for spark-ignited and compression ignition engines, based on the ARB's data. (CNGVC1)

Comment: As an alternative to the current single EER of 0.9, if the Board decides not to establish separate values, we would ask the Board to apply an EER that blends the values for spark-ignited and compression ignition engines, based on the ARB's data. (CE1)

Comment: In addition, WSPA is very concerned about the value of the EER assigned to heavy-duty CNG engines in the proposed regulation. (WSPA1)

Comment: To date, our comments have yet to be addressed by staff despite the fact that this modification of the EER value fails to capture the actual performance of a compression ignition natural gas engine. CARB's EER value for this category is based exclusively on a natural gas spark-ignited engine. (CE1)

Comment: However, looking at CARB's own data to determine the EER, it is clear that CARB should either create two EER values for two very different engine strategies or blend the two EER values if the proposed LCFS regulation disallows the use of two EER values. Since the category claims to represent both engine strategies, a blend seems most appropriate if one EER value is used. (CE1)

Comment: Unfortunately, blending spark-ignited and compression-ignition technologies will penalize the engine strategies that are more efficient, but less so than CARB current proposal to incorrectly tie the EER value to spark-ignited engines exclusively. (CE1)

Comment: To sum up, Clean Energy is asking CARB staff and the Board to direct the staff to:

1. Assign a separate EER value to spark-ignited engines and a separate EER value to compression ignition engines that is reflective of each engine's performance; or
2. Assign a blended EER value that reflects both spark-ignited engine and compression ignition engine performance (based on the data) to more accurately reflect the "Compressed or Liquefied Natural Gas Used in a Heavy-Duty Spark Ignited or Compression Ignition Engine" EER category. (CE1)

Comment: Establish two EER values for spark-ignited engines and

compression ignition engines respectively. (CE1)

Comment: And another point that we want to say is that I think the issues that was brought regarding the CNG, needs to be considered and looked more carefully. And we recommend that you direct the staff to look into this issue brought forth by the Westport and Clean Energy and see if there is a need for the modification that can be brought before the Board when the staff comes back to you in December. (CCA)

Comment: It's about this EER. I'll be brief with 2 different engines with 2 different energy economy ratio values. What we certainly don't want to see happen is for an engine with superior GHG reduction capacity to be undervalued. The only way to really do that is to adopt 2 different numbers. I understand there's a challenge doing that. But at a minimum then we'd like to see a blended number that takes into account both of the engines. And it's ARB's own certification data that shows that the compression ignition suffers no fuel penalty. And we don't want to be punished because we have a 2010 compliant engine and others don't. (CNGVC2)

Response: These comments are based on the different characteristics between compression-ignition engines and spark-ignited engines, both of which can be designed to use CNG as the fuel. In compression ignition engines, the fuel is ignited without a ignition source; in such engines, the fuel is compressed to a level of pressure and temperature that is high enough to cause ignition of the fuel without a spark. By contrast, a spark-ignition engine relies on a source of sparks (i.e., a spark plug) to initiate the combustion of the fuel/air mixture after it is compressed.

The staff agrees that the compression-ignited CNG engines have fuel efficiencies close to that of diesel. However, at this time no compression-ignited CNG engines have been certified to the ARB's 2010 emissions standards, so it is not clear how many of these engines will be in use in the period of 2010 to 2020 when most of the emissions credits will be earned. It is for this reason that the staff has not included compression-ignited CNG engines in the calculation of EER for heavy-duty CNG engines. When the compression-ignited CNG engines achieve certification to the ARB's 2010 emission standards, the staff will include them in the calculation of the EER for heavy duty CNG engines, either by calculating an average EER for spark-ignited and compression ignited engines, or by including in the LCFS separate EERs for spark-ignited and compression-ignited engines. The staff's current estimate of EER is based on the most recent certification data. Any future changes to the EER will also be based on the most recent certification data.

C-187. Comment: WSPA recently sponsored a technical evaluation of energy economy ratios (EER's) developed for the LCFS regulation. We are disappointed that the methodologies developed as part of that study were ignored by ARB staff, as EEA's treatment of on-road fuel economy and vehicle attribute differences for light-duty vehicles has a very sound technical basis.

(WSPA1)

Response: The staff did not ignore the methodologies used in the WSPA-sponsored study. The staff disagrees with many of the assumptions that were made in the study, and thus believes that the EERs calculated in the study do not accurately represent the EERs of vehicles that will be in use during the period in which LCFS credits will be earned.

C-188. Comment: The EER for heavy-duty CNG in this rulemaking should be based on the current vehicle fleet (EEA recommends a value of 0.7, based on available data). (WSPA1)

Response: An EER of 0.7 might be representative of some of the spark-ignited CNG engines that are currently being used, but many of these engines are being replaced by advanced technology spark-ignited engines with EERs closer to 0.9. We believe an EER of 0.9 is more representative of the EER of engines that will be used in the period of 2010 to 2020 when most of LCFS credits will be earned.

C-189. Comment: To the extent that more efficient advanced technologies are implemented, the EER value can be updated, perhaps as part of the Program Reviews. Establishing an overly optimistic EER that is not representative of the existing heavy-duty CNG fleet sets up a mechanism in which LCFS credits can be generated that are not justified or real. (WSPA1)

Response: In Resolution 09-31, the Board found that the regulation, including the EER for heavy-duty CNG engines, was based on the best available and most defensible economic and scientific information. Therefore, the EER for heavy-duty CNG engines is not overly optimistic and represents the EER of most of the heavy-duty CNG engines that will be used from 2010 to 2020, when most of the credits in the LCFS will be earned.

C-190. Comment: While ARB's estimates of emissions associated with indirect land use change have generated the most debate, CALSTART notes that there are other areas of uncertainty that deserve additional attention. One factor that can easily tip the balance between various fuels is the Energy Economy Ratio (EER). Like indirect land use, this area has generated disagreement and a wide range of estimates. ARB staff admits that "the data are relatively limited" for establishing EER values for advanced and emerging vehicle technologies. (CALSTART)

Response: The staff agrees that there can be uncertainty in the EER due to vehicle-to-vehicle variations in fuel efficiency. The staff believes that its EERs have been calculated using all of the most current and relevant data on fuel economy and engine efficiency. The staff has committed to periodically reviewing the EERs and making any necessary changes if new data or studies suggest different EER values are more representative.

C-191. Comment: This is one of several examples of Staff admittance to their own lack of confidence and non-reliability of their estimates that flaw their economic analysis. Yet they appear determined in rushing to implement the LCFS without any certainty of its implications, ramifications, or consequences. Another example: On Page ES 18, Staff admits that "However, for advanced technology or emerging vehicles such as battery electric vehicles (BEV), plug-in-hybrid electric vehicles (PHEV), fuel cell vehicles (FEV), and heavy-duty compressed natural gas (CNG) or liquefied natural gas (LNG) vehicles, the data are relatively limited. Therefore the Staff has provided EER values that are to be used until such time that there is more robust data available to better establish the EER." To tout the benefits of alternative fuel vehicles and their fuel efficiency without having robust estimates seems to be premature on the part of Staff. (CSBR2)

Response: While there is currently limited data available on the efficiencies and fuel economy of advanced fuel and technology vehicles such as fuel cell vehicles, battery electric vehicles, and plug-in hybrid electric vehicles, it is clear that these vehicles have significantly higher energy efficiency than gasoline vehicles and thus have significantly lower per mile carbon emissions than gasoline vehicles. In order to accurately estimate the per mile carbon emissions of these vehicles it is imperative that the greater energy efficiency of these vehicles be included in the calculation of carbon intensities. The staff has done this by calculating EERs using the available and relevant data. It is not premature to include in the calculation of emission benefits of advanced technology vehicles improvements in fuel efficiency just because there is limited data, when it is known that these vehicles have substantially higher energy efficiency and lower per mile carbon emissions. Also, there is evidence through vehicle sales that these vehicles will be more prevalent in the future and the staff is committed to reviewing new data and revising numbers as appropriate.

C-192. Comment: We ask that the Board respect the same need for accuracy in accounting for the efficiency of different natural gas engines. (CNGVC1)

Response: The staff has and will continue to ensure that its calculations of energy efficiency for natural gas engines are accurate and include all of the most relevant data.

C-193. Comment: Annual Energy Economy Ratios (EER) updates to reflect real world fleet fuel economy changes. The fuel efficiency assumptions underlying both gasoline and diesel compliance paths are extremely important, as they effectively define the degree of downstream GHG emissions embedded in the LCFS. (SCAQMD1)

Response: The staff agrees with this comment. It is for this reason that the calculated EERs include the most recent and relevant data on fuel economy and energy efficiency. The Board has directed staff to review and update EERs as appropriate.

C-194. Comment: Several Energy Economy Ratios (EERs) used in the LCFS are based on only two data points per category. Such a limited data base may not

capture important trends in baseline fuel economy occurring in the fleet during the time the regulation is being implemented. Furthermore, in March, 2009, revisions to the 2011 model year Corporate Average Fuel Economy Standards were proposed which relax the standards in the near term for both light duty passenger cars and light trucks. Such diminished fuel economy standards have a direct and adverse effect on the EER trends reflected in the LCFS baseline. Furthermore, a recent Massachusetts Institute of Technology study has found, for example, that the fuel economy disparity between gasoline and diesel engines is expected to shrink appreciably to near-parity levels with the advent of direct injection gasoline technology. (SCAQMD1)

Response: The staff agrees that some of the EERs are calculated on limited data, but disagrees that this limited data may not capture important trends in baseline fuel economy occurring in the fleet during the time the regulation is being implemented. There are very clear trends in the energy efficiency of advanced technology vehicles such as fuel cell vehicles, plug-in hybrid electric vehicles, and battery electric vehicles relative to conventional gasoline vehicles. These advanced technology vehicles achieve significantly greater energy efficiency than gasoline vehicles, and thus result in lower per mile carbon emissions. The staff's inclusion of the EER in the calculation of emissions and carbon intensity of the LCFS accurately recognizes the benefits of advanced-fueled vehicles even though the calculation is based on only a few data points in some cases. The staff has committed to making any needed revisions to these calculations if warranted by the emergence of additional, relevant data. Changes in the Corporate Average Fuel Economy (CAFÉ) standards have a second order impact on the values of EER. The staff will consider the magnitude of the effect on EER values of changing CAFÉ standards when it reviews the need to change EER values in light of additional, relevant data on energy efficiency of advanced technology vehicles. The relative difference in fuel economy between gasoline and diesel vehicles is not relevant in the LCFS because gasoline and diesel each has its own individual standards which are required to be met. That is, gasoline vehicles do not comply with the diesel standard and diesel vehicles do not comply with the gasoline standard, so the energy efficiency of gasoline vehicles relative to diesel vehicles does not come into play in determining compliance with either of the two standards.

C-195. Comment: AQMD staff therefore recommends that the EER values used in the LCFS be updated routinely as new data become available. (SCAQMD1)

Response: The staff will implement this recommendation and will update the EERs, if necessary, as new data and information becomes available.

C-196. Comment: Provide incentives for optimization of the fuel and vehicle as a system. Opportunities for the optimization of plug-in electric vehicles (PHEVs) for GHG and criteria emissions levels may be greater with alternative fuels than solely with conventional gasoline. The LCFS should provide some mechanism to leverage these synergies. (SCAQMD1)

Response: The LCFS regulation is the first step in reducing the GHG contributions from the full, lifecycle emissions of transportation fuels used in California. The LCFS is part of the broader AB 32 Scoping Plan that provides California's roadmap for reducing GHG emissions. Mechanisms such as those suggested by the commenter can be part of a comprehensive and longer term program for reducing GHG emissions from both fuels and vehicles. The interactions between such mechanisms can be complex and have unforeseen or unintended consequences. Thus, implementing the suggested mechanisms will require extensive analyses, policy considerations, and development of regulatory or market-based mechanisms. We look forward to working with stakeholders to identify additional ways to refine the LCFS and enhance its effectiveness.

C-197. Comment: Provide incentives for optimization of the fuel and vehicle as a system. Table 5 in Section 95485 of the proposed regulation provides key data inputs regarding the Energy Economy Ratio (EER) for various fuel/vehicle combinations. There is significant technology evolution occurring with respect to alternative fuel and electric drive vehicles. The values in Table 5 do not currently provide estimates of optimized vehicles in some of these categories, as they imply that PHEVs are optimized to run solely on gasoline. (SCAQMD1)

Comment: Provide incentives for optimization of the fuel and vehicle as a system. AQMD staff recommends that CARB provide a default case for alternative fuel PHEVs, including an optimized FFV EER value. Such additional vehicle default values would reflect the optimization of downsized steady state engine which also takes advantage of fuel properties such as the latent heat of vaporization, which is three times higher for E85 compared to gasoline. Increased compression ratios, for example, have been demonstrated on E85 FFVs which approach the fuel economy parity of gasoline engines. Hybridized natural gas vehicles could also be further enhanced to bias the use of natural gas rather than gasoline in setting engine parameters such as compression ratio. (SCAQMD1)

Response: The EER values in Table 5 of 95485 are the staff's best estimate, based on the available relevant data on fuel economy and engine efficiency, of the energy efficiency of advanced technology vehicles relative to gasoline and diesel vehicles. While these vehicles may not be optimized, they reflect the staff's best estimate of the real world energy savings that would result from their use in place of gasoline and diesel vehicles. Thus, these are the most appropriate EERs to use in calculating the carbon intensities for advanced fuel and technology vehicles. The staff has committed to review these EERs as new relevant data on fuel economy and engine efficiency becomes available to determine if any revisions to the EER are warranted.

C-198. Comment: EER of EVs and FCVs is Too Low Relative to Gasoline Vehicles in the 2010 to 2015 Timeframe. LCFS EER table compares 2010 EVs and FCVs against 2015 gasoline vehicles. This is inconsistent, and it artificially lowers the credit for EVs and FCVs during the 2010 to 2015 timeframe. (HONDA)

Response: The staff believes that it is necessary to take into account the fact that the fuel economy of gasoline vehicles will be increasing during the 2010 to 2015 timeframe due to the requirements of the ARB's regulations adopted pursuant to AB 1493 (Pavley). As a result of these fuel economy increases, the energy efficiencies of advanced fuel vehicles such as electric vehicles and fuel cell vehicles relative to gasoline and diesel vehicles is expected to decrease over time. The ARB has committed to a periodic review of the EERs, and as part of this review will make any necessary changes to the EERs if warranted by new data and information on energy efficiencies and fuel economies.

C-199. Comment: EER of EVs is Too High. LCFS should use real laboratory dynamometer test results using existing standards for both City and Highway tests to build the EER comparisons. (HONDA)

Response: The EER for electric vehicles is based on the staff's best estimate of the real world energy efficiencies and fuel economies for these vehicles. Where available, the staff has used both city and highway fuel economies to estimate real world fuel economies. Where the city and highway fuel economies are not available, the staff has estimated real world fuel economies for electric vehicles using available information on electric vehicle battery capacity and full-charge vehicle range.

C-200. Comment: EERs of FCVs and EVs are too low for 2010 to 2015. To reflect the impact of AB 1493 (Pavley Regulations), the LCFS reduces the EER of FCVs and EVs in the 2010 to 2015 timeframe. This effectively reduces the incentive to apply these vehicles and fuels in the early years. Comparison of 2010 EVs and FCVs to 2015 gasoline vehicles puts today's advanced vehicles at a distinct disadvantage. These vehicles actually DO have an EER of 3.0 to 3.5 vs. regular gasoline vehicles in the 2010 timeframe. (HONDA)

Response: The staff anticipates that the large majority of the credits earned by electric vehicles and fuel cell vehicles will be earned in the period 2015 to 2020. It is for this reason that the EERs for electric vehicles and fuel cell vehicles were calculated assuming that the fuel economies of the gasoline vehicles had increased by 30 percent to the 2015 requirements of the ARB's AB 1493 (Pavley) regulations.

C-201. Comment: The EER of EVs is too high. The LCFS should reference a specific test mode, or test procedure, to ensure that fuel economy comparisons to gasoline vehicles are being conducted on a fair basis. Section 49CFR (EPA), ARB, SAE all have standard test modes. The methods used to calculate fuel economy in the LCFS are not consistent with any of these. In the absence of data, the LCFS uses press release materials for sources in some instances. Test conditions and procedures are rarely disclosed in press releases, so it is difficult to determine what the press release actually means! In calculating the City/Hwy combined fuel economy, the LCFS makes the assumption that the City and Highway test data are equal in absence of measured data. This is not a good assumption, as the City and Hwy tests usually result in very different

results, especially for electrically driven vehicles. Only comparable City/Hwy Combined fuel economy results should be used to generate the EER table. These vehicles exist – it should be possible to get real data and to base the EER calculations on real data.

- EPA is one source for vehicles that have been certified.
- ARB has established a test procedure for PHEVs
- Argonne National Labs has an extensive test vehicle database.

In building the EER Table, ARB lacks certain data, such as the HWY dynamometer test result for the GM Volt. The results are inaccurate. This compares the BEST mode of the EV vs. the WORST mode of the gasoline vehicle. The Hwy fuel economy test of the Cobalt is 43.4 mpg, but the higher fuel economy of the Cobalt in Hwy mode is not captured in the EER table. This uses press release information for the City only fuel economy of the Volt versus the laboratory test result of the City fuel economy of the Cobalt. The LCFS is assuming that the Hwy test result of the Volt would be similar to the City result, but lacking any data, this assumption is not valid. (HONDA)

Response: The staff has used data published by the U.S. Department of Energy and U.S. Environmental Protection Agency on vehicle fuel economy (where available) to calculate the EERs. This data was obtained from standard test procedures that simulate both city and highway driving. Where not available, the staff estimated fuel economies for electric vehicles using estimates of battery capacity and vehicle range. The estimates of vehicle range are assumed to represent a combination of city and highway driving, which the staff believes is the most reasonable assumption to make. Thus, the staff believes that the fuel economy comparisons are indeed being conducted on a fair basis. The staff believes that it is reasonable to assume that vehicle ranges published in press releases represent a combination of both city and highway driving, as nearly all drivers engage in both city and highway driving. It seems reasonable then to assume that the publishers of the press releases would be interested in informing most drivers of the likely range of electric vehicles, and that these published ranges would then represent some combination of both city and highway driving.

Other published data for plug-in hybrid electric vehicles such as the Argonne National Labs data actually supports the ARB's calculation of EERs for plug-in hybrids. The staff did not use this data because the plug-in hybrid vehicles in this test program were tested in a blended mode, meaning that the vehicle was being powered by both electricity and gasoline during the testing process. The staff is interested only in the fuel economy of plug-in hybrids during the purely electric mode because the LCFS gives credit only for the amount of grid electricity used by a plug-in hybrid. The staff is interested in how much gasoline is being displaced by the grid electricity used by plug-in hybrids. The fuel economy data from the Argonne study can be adjusted to give the fuel economy of the plug-in hybrid vehicle if it were operating in the electric mode only. This adjustment gives a fuel economy estimate for plug-in hybrids that is very close to the estimate made by the staff on the basis of battery capacity and vehicle range.

When additional data from standard test procedures becomes available for plug-in hybrid vehicles, the staff will review its calculation of the EER to determine whether any changes need to be made to EER for electric vehicles.

C-202. Comment: Given that natural gas engines have historically been significantly cleaner on criteria air pollutants than their diesel counterparts, it is reasonable to assume that the natural gas version of the ISX will maintain its clean air advantage over diesel and be on par with diesel for efficiency. (CE1)

Response: This is not necessarily true. Diesel engines with advanced emissions control technologies meeting the ARB's 2010 standards will have criteria pollutant emissions levels comparable to those of natural gas engines. The low levels of emissions of criteria pollutants for natural gas engines do not imply that the fuel efficiency of a natural gas engine will be comparable to that of a diesel engine.

C-203. Comment: Finally, we would like to see a credit under the EER for biodiesel for the renewable fuel to displace gasoline. (COMF3)

Response: Biodiesel will be subject to the diesel requirements of the rule. The ARB made a policy decision that fuels that substitute for gasoline would be subject to the gasoline standard and fuels that substitute for diesel would be subject to the diesel standards. Because biodiesel substitutes for diesel, it is subject to the diesel standard. Because there is no credit given to diesel for its greater efficiency compared to gasoline, there is no credit given to biodiesel.

C-204. Comment: In summary, Community Fuels would like the ARB to consider the following changes in order to promote California-based biodiesel production that will be critical to reducing our dependence on fossil fuels and will aid in the development of a low carbon fuel industry:

1. Increasing conventional biodiesel demand for years 2011 to 2013.
2. Providing EER credit for biodiesel powered light duty vehicles. (COMF2)

Response: The staff believes that the current regulatory requirements of the LCFS rule provide incentive for the greater use of biodiesel in a reasonable timeframe. Currently, there are no emission data that shows that engines using biodiesel have greater fuel efficiency than engines using petroleum diesel. If future emission test data for biodiesel indicates that engines using biodiesel fuels have greater efficiency than petroleum diesel the staff will consider amending the LCFS regulation to include a different EER for biodiesel.

C-205. Comment: The development of energy economy ratios is straightforward with the current fleet, in which nearly all light-duty vehicles are gasoline powered, but a light-duty fleet with greater diesel presence, as was present in the past and is likely to be in the future, would require a modification to the approach. Eventually, propulsion technologies and vehicles will be produced without consideration of whether they are "replacing" gasoline- or diesel-fueled engines. How will energy

economy ratios for such vehicles be calculated, i.e. to which fuel's carbon intensity baseline will they be compared? For example, hydrogen producers whose product is used to fuel light-duty vehicles could argue that the hydrogen is replacing diesel fuel because there are some light-duty diesel-powered vehicles currently in existence, at least in other parts of the country if not California. (PEERREVIEW1)

Response: The staff has made a policy decision that the EER ratios for all light duty vehicles and fuels used in light duty vehicles will be computed using the fuel efficiency of gasoline vehicles as the baseline since the great majority of light duty vehicles in the current fleet are gasoline vehicles. Therefore, for purposes of calculating credits, it is logical and reasonable to assume that any fuel used in light duty vehicles is displacing gasoline. If the future composition of the light duty vehicle fleet changes significantly in the future and diesel vehicles achieve a greater presence, the staff will reevaluate this assumption and the need to make any changes.

C-206. Comment: Energy economy ratios certainly must be included to adjust for the different efficiencies of propulsion technologies in converting a certain amount of energy into linear motion. It would be instructive to report how variable the EER is across vehicle sizes. For example, what is the EER for a compact electric car versus a compact gasoline-powered car, and what is the EER for a large electric SUV versus a large gasoline-powered SUV? If the difference is large, multiple EERs may be needed for different vehicle classes. (PEERREVIEW1)

Response: Currently, there is not enough published relevant data on energy efficiencies of different sizes, types, and models of alternative fueled-vehicles such electric vehicles to perform a more detailed, category-specific analysis of EERs. If more data on energy efficiency of alternative-fueled vehicles becomes available in the future, the staff will consider the possibility of developing category-specific EERs.

C-207. Comment: The EER for plug-in hybrid electric vehicles (PHEVs) will require much more careful calculation once they are commercially available for testing. The value will depend very much on whether the vehicle is operating purely on electric power over its first 30 miles or on its hybrid gasoline engine after this point. CARB will need to be able to make informed assumptions about the everyday use characteristics of PHEVs in order to determine an appropriate EER. How will updated EERs be handled? (PEERREVIEW1)

Response: The staff agrees that the EER for plug-in hybrid vehicles will have to be reanalyzed once these vehicles are commercial and there is test data on their fuel efficiency. The staff agrees that the fuel efficiency and EER will depend greatly on whether the vehicle is operating in the purely electric mode or the hybrid mode. However, for purposes of calculating credits and compliance under the LCFS, the staff is only interested in the fuel efficiency and fuel economy in the purely electric mode because the LCFS gives credit only for the amount of grid electricity that is used by plug-in hybrid vehicles. The LCFS gives credit only for the amount of gasoline that is

displaced by the amount of grid electricity that the plug-in hybrid vehicle uses. So the relevant fuel efficiency for purposes of calculating the EER for plug-in hybrid vehicles under the LCFS is the fuel efficiency in the purely electric mode. As soon as the vehicles are commercial and test data on fuel efficiency are available, the staff will reevaluate the need to update the EER in the LCFS.

C-208. Comment: Finally, with regard to EERs, a discussion of the importance of idling by heavy-duty trucks is warranted because EERs are not valid during idling. Does idling comprise a sufficiently small fraction of total diesel consumption that it can be neglected? Are idle reduction programs in place in California? What are the carbon intensities for "shore" electric power replacing diesel consumption in this case? (PEERREVIEW1)

Response: The ARB has adopted regulations that limit the idling time of diesel vehicles. These regulations ensure that the amount of diesel fuel burned during idle is a very low fraction of the total fuel burned. As a result, the fuel efficiency of diesel vehicles is not significantly reduced as a result of idling. Therefore, idling will not have a significant effect on the EERs for fuels and vehicles that are calculated relative to heavy duty diesel vehicles. The staff would assume that the carbon intensity of shore electric power is the same as the carbon intensity of electricity used to power electric vehicles. However, the fuel used to produce shore electric power will not be subject to the LCFS.

C-209. Comment: Table ES-7 lists the energy economy ratio for electricity substituting for diesel as 3.0, but everywhere else in the report, this value is given as 2.7. (PEERREVIEW1)

Response: The correct EER for electricity substituting for diesel is 2.7. The reference to 3.0 is an error.

C-210. Comment: In Brazil, development of flex-fuel vehicle technologies with higher compression ratios has provided an opportunity to increase the efficiency of vehicles using ethanol fuels somewhat. ERB may not want to incorporate this potential into its LCFS EERs, but this potential may warrant at least a one-sentence mention. (PEERREVIEW3)

Response: The flex-fueled vehicles used in the United States have the same energy efficiencies as gasoline vehicles. Therefore, the EER in the LCFS regulation for these vehicles is 1.0. The staff will review the data on flex-fueled vehicles in Brazil with higher fuel efficiencies and EERs, and the likelihood that any of these vehicles will be used in the United States, and will then determine if any revisions need to be made to the EER values.

C-211. Comment: WSPA would like confirmation that ARB will not allow regulated parties to develop their own EERs. (WSPA1)

Response: There is currently no provision in the regulation that would allow regulated

parties to develop their own EER values.

C-212. Comment: Comparisons must be made based on on-road fuel economy rather than fuel economy derived from FTP-based laboratory testing. This is particularly important for battery electric vehicles which can be significantly impacted by ambient temperatures, use of air conditioning and heating, road grade, and other factors not typically accounted for in laboratory testing. (WSPA1)

Response: The staff agrees that there are many parameters that can affect fuel economy. The staff believes that most of the parameters that have the greatest effects on fuel economy have been incorporated into the EPA's most recent test procedures for fuel economy. Therefore, the staff believes that the use of data from these procedures is sufficiently accurate for purposes of calculating the EERs that will be used in the LCFS. As more electric vehicles are commercialized, the staff will review the data that are used to calculate EERs to determine if any revisions to the values used in the LCFS need to be made.

C-213. Comment: Comparisons must be made based on vehicles with similar attributes (e.g., acceleration, aerodynamic drag, low rolling resistance tires, etc.) in order to separate vehicle effects from fuel effects. (WSPA1)

Response: The staff agrees that comparisons must be made based on common attributes. To the extent possible, the staff's calculated EER values reflect common vehicle attributes.

C-214. Comment: The EERs developed by EEA are lower than those currently in the December 2008 draft LCFS regulations for nearly all fuels and technologies. This is a result of EEA's more rigorous treatment of on-road fuel economy and differences in attributes among vehicle types. For light-duty battery electric vehicles (BEVs), the EER of 3.4 recommended by EEA is 15 percent lower than CARB's estimate of 4.0, even though EEA stated that 3.4 reflects an "optimistic EER for the 'best' EVs" included in their study. For light-duty plug-in hybrid electric vehicles (PHEVs), the EER under all-electric mode calculated from EEA's recommendations is slightly higher than that proposed by CARB staff. For hydrogen FCVs, both light-duty and heavy-duty EERs recommended by EEA are lower than CARB's estimates. Also, the December 2008 draft regulations assign the same EER to hydrogen FCVs and internal combustion engine vehicles (ICEVs). This makes no sense and is not supported by any data. As noted by EEA, these engines do not even offer an EER of 1.0 on a comparable attribute basis and should not be grouped with FCV models.

A significant difference highlighted by the EEA analysis is the EER for heavy-duty CNG vehicles. Given the inherently better efficiency of diesel versus spark-ignition engines, CARB's initial selection of 1.0 for CNG heavy-duty vehicles was somewhat surprising. As noted in the EEA report, the recommended EER of 0.7 is based on the assumed use of stoichiometric operation to meet NOx standards.

If lean-burn engines are produced that meet the 2010 NOx level, or if systems utilizing a diesel/natural gas fumigation approach are developed, the EER of 0.7 should be revisited to reflect the potential efficiency improvements of those systems. (WSPA1)

Response: Some of the data used in the EEA's analysis is not relevant for purposes of estimating the EERs of light duty vehicles, particularly for plug-in hybrid vehicles. Also, the EERs estimated by EEA for light duty vehicles do not take into account the fact that the fuel economy of gasoline vehicles, used as the baseline for light duty vehicle EER calculations, will be increasing over time as a result of ARB regulations. The staff agrees that the EER for fuel cell vehicles should not be the same as for hydrogen internal combustion engines, and has made the appropriate change in the LCFS regulations.

The staff agrees that spark-ignited CNG engines would generally have lower fuel efficiency than compression-ignited CNG engines. Because most of the CNG used in heavy-duty engines is used in spark-ignited engines, the average EER for CNG used in heavy duty engines will be less than 1.0. The value of 0.9 in the LCFS is based on the staff's calculation using recent certification data. The 0.7 value calculated by EEA is based on existing engines which are using older engine technology and are being phased out in favor of engines with new technology and greater fuel efficiency. The staff expects that most of the heavy-duty CNG engines will be newer technology engines during the period when most of the LCFS credits will be generated.

C-215. Comment: A significant shortcoming in the development of EERs is the lack of data on production-ready, alternative fuel vehicles such as PHEVs and hydrogen FCVs. As a result, it is imperative that CARB re-evaluate the EERs when data are available on OEM production vehicles (accounting for on-road fuel economy and differences in attributes as recommended by EEA).

As noted above, a revised set of EERs for light-duty vehicles was presented by CARB staff at the January 30, 2009 workshop. It is our understanding that those EER estimates include an adjustment for projected fuel economy improvements to the baseline conventional vehicles to account for AB 1493 and federal CAFE standards. Such an adjustment is appropriate and should be included in EER estimates developed for future model year vehicles. However, if that adjustment is applied to conventional gasoline vehicles, every effort should be made to ensure that the alternative fuel vehicles being analyzed also reflect the technology anticipated for the same timeframe as the conventional vehicle estimates. In this way, an "apples-to-apples" comparison is made.

Another issue related to the selection of an appropriate baseline vehicle arises when evaluating EERs for PHEVs. The ratio of operation on electric power to operation on gasoline/diesel is appropriate since it is clear that electricity is displacing the fuel that would have been used if the vehicle was run in "conventional" hybrid electric vehicle mode. In the case of BEVs and FCVs, the

baseline vehicle (i.e., the denominator in the EER calculation) used in CARB's December 2008 EER estimates and in the EEA study is a conventional gasoline vehicle. However, given future fuel economy requirements, it may be more appropriate to use a conventional hybrid electric vehicle as the baseline vehicle since that is likely what would be displaced by a BEV or FCV. In any case, the selection of baseline vehicle technology should change moving forward to reflect the improved fuel economy of the new conventional vehicle fleet at the time the alternative fuel vehicles are introduced.

EEA's analysis of EERs for "blended" PHEVs brings up an interesting question about how best to evaluate the EER for the electricity used during the charge-depleting mode when the gasoline or diesel engine can turn on and off in response to power demand. If this configuration of PHEV is ultimately marketed, CARB will need to develop guidance on how to estimate EERs for these vehicles; it should not be simply assumed that they would have the same EER as an extended-range PHEV or a BEV.

Expanding on the issue of electricity used in PHEVs (and BEVs), it is imperative that CARB require documentation that electricity was actually used to power the vehicle. This is very important in the case of PHEVs where there is no operational requirement that the vehicle be plugged in to run. (WSPA1)

Response: The staff agrees that a shortcoming in the development of the EERs is the lack of data on production-ready engines, and has committed to reviewing the EER calculations and proposing any needed revisions when more data is available on production-ready vehicles. The staff will include in any calculations the effects, if any, of anticipated future improvements in technology that would increase the fuel economy of advanced technology vehicles like the improvements that will be made to gasoline vehicles in order to comply with the ARB's AB 1493 (Pavley) regulations.

The staff does not believe that a conventional hybrid electric vehicle should be used as the baseline light-duty vehicle for purposes of calculating EERs. There are still a relatively small number of these types of vehicles in the light-duty vehicle fleet, and thus, they are not representative of what most people are driving. If at some point conventional hybrid vehicles become a significant portion of the total fleet, the staff will evaluate whether the EERs for light-duty vehicles should be recalculated with conventional hybrids used as the reference vehicles.

The staff will also follow the compliance progress for the AB 1493 regulations to understand the improvement in fuel economy of conventional gasoline vehicles, and make any needed changes to the light-duty EERs to reflect these changes.

For plug-in hybrid electric vehicles, the relevant fuel efficiency for purposes of computing the EER is the fuel efficiency in the purely electric mode, which usually corresponds very closely to the charge depleting mode. For purposes of calculating credits and compliance under the LCFS, the staff is only interested in the fuel efficiency

and fuel economy in the purely electric mode because the LCFS gives credit only for the amount of grid electricity that is used by plug-in hybrid vehicles. The LCFS gives credit only for the amount of gasoline that is displaced by the amount of grid electricity that the plug-in hybrid vehicle uses. So the relevant fuel efficiency for purposes of calculating the EER for plug-in hybrid vehicles under the LCFS is the fuel efficiency in the purely electric mode.

The staff agrees that it is not correct to assume that plug-in hybrid vehicles operating in the charge depleting mode have the same efficiency as plug-in hybrid vehicles operating in an extended-range mode. The staff is not currently making this assumption and will not make it in the future. When plug-in hybrid electric and battery electric vehicles are available the staff will reevaluate the need to revise the EERs for these vehicles on the basis of available fuel efficiency data.

For purposes of awarding credits under the LCFS, the staff plans on requiring documentation of the amount of electricity that was actually used to power the vehicle.

C-216. Comment: Recent research suggests that GHG emissions associated with lithium-ion battery materials account for 2 percent to 5 percent of lifecycle emissions from plug-in hybrids. Previous LCA studies have assumed that vehicle manufacturing emissions are negligible and can generally be ignored. However, for the case of BEVs and PHEVs, we recommend that CARB staff verify that battery manufacturing emissions are negligible and can be ignored for the LCFS. If not, this effect would probably best fit as an adder to the well-to-tank estimates for electricity generation and not necessarily in the EERs. Similarly, the energy used to make 10,000 psi tanks for hydrogen storage can be significant. (WSPA1)

Response: In Resolution 09-31, the Board found that the LCFS regulation as approved was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective GHG emission reductions from transportation fuel used in California. The Board made this finding with consideration of comments submitted up to and including the Board hearing in April 2009, which includes this commenter's letter. To ensure that the LCFS continues to reflect the best available data, in Resolution 09-31 the Board directed staff to monitor the implementation of the regulation and to propose amendments to the regulation for the Board's consideration when warranted. Further, section 95489 mandates two program reviews that will cover, at a minimum, advances in full, fuel-lifecycle assessments, which may include advances in LCA studies such as those suggested by this commenter.

C-217. Comment: The EER values for electric and fuel cell vehicles in the LCFS analysis are inconsistent with the treatment of these exact technologies under the Pavley regulations (Section 1961, Title 13, California Code of Regulations). The Pavley regulations set standards for greenhouse gas emissions from new vehicles and one can simply estimate EERs for electric and fuel cell vehicles

from these standards and emission factors assigned by the regulations to electric and fuel cell vehicles. For example, for purposes of the Pavley regulations, all electric vehicles are assigned an emission rate of 130 grams of CO₂ equivalent emissions per mile while all fuel cell vehicles are assigned a value of 210 grams per mile. Standards for passenger cars are 301 grams per mile for the 2010 model year and 205 grams per mile for the 2016 model year. These values would indicate that the EER for electric vehicles should change over time and start at about 2.3 for 2010 model year vehicles and decrease to 1.6 for 2016 model year vehicles. In either case, the value is far lower than the 3.0 in the proposed LCFS regulations. Similarly, the EER for hydrogen vehicles would decrease over time from 1.43 in the 2010 model year to 0.98 for the 2016 model year. (WSPA1)

Response: The emission rates assigned to different vehicles in the AB 1493 Pavley regulations do not accurately reflect the differences in fuel economies between the different types of vehicles. The emission rates in the AB 1493 Pavley regulations are only an indication of how much credit each type of vehicle will be given under the regulations. The EERs calculated by the staff for the LCFS regulation are better indications of the actual differences in fuel economy between different types of vehicles. Therefore, the staff believes that these EERs are most appropriate for purposes of calculating credits under the LCFS.

C-218. Comment: In addition to the EER values of 3 and 2.3 for electric and fuel cell light-duty vehicles, the LCFS also proposes EER values of 2.7 and 1.9 for electric and fuel cell heavy-duty vehicles, respectively. Again, these values are based on limited data. (WSPA1)

Response: The staff agrees that EERs for both electric vehicles and fuel-cell vehicles are based on limited data because there are limited numbers of electric and fuel-cell vehicles at this time on which to base such EER calculations. However, it is important to emphasize that the limited data have no significant effect on the LCFS' projected benefits in the early years of the program. This is because the compliance schedule is back-loaded (i.e., the more stringent requirements occur in the latter phase of the program, from 2015-2020), there are very few of these vehicles presently in California, and the LCFS is not expected to result in a substantial increase in these vehicles in the early years of the program. With that said, the staff are committed to reviewing and revising the EERs, if necessary, when the vehicles are commercially available and more data and information are available on the energy efficiency and fuel economy of these vehicles.

C-219. Comment: The Board should consider revising the Energy Economy Ratio (EER) for CNG and LNG vehicles that use newer stoichiometric engines. These 2010-compliant engines have fuel economies that are essentially the same as 2010-compliant diesel engines and therefore should reflect an EER of 1.0, rather than the 0.9 EER currently specified for non-stoichiometric CNG/LNG engines (i.e., lean-burn engines). (CCA, CNGVC1)

Response: The Board considered this and similar comments and found it unnecessary to incorporate the suggested change into the regulation as approved. However, the Board directed the Executive Officer in Resolution 09-31, as part of the LCFS implementation activities, to re-evaluate the EER for heavy-duty vehicles powered by CNG and LNG and update the EER for these vehicles as soon as possible. Further, the Board expressly delegated to the Executive Officer the authority to conduct rulemakings to adopt new or modify an existing EER in section 95485(a) of the LCFS regulation.

Treatment of Blendstocks and Crude Oil

C-220. Comment: ARB is inappropriately using ASTM D6751 and D4608 in reference to B100 and E100 as finished fuels in the opening paragraph. Both of these specifications are for the use of each respective material as a blend stock to be added to a petroleum base, e.g. B5 and E10. They are totally inadequate as finished fuel specifications for either B100 or E100. (WSPA1)

Response: The commenter appears to misunderstand the regulatory language. With regard to B100, we agree that it generally is not considered a finished fuel because it is not subject to motor vehicle fuel specifications promulgated by either ARB or Division of Measurement Standards. As such, B100 is not legal for sale as a finished fuel except under limited, developmental engine-fuel variances pursuant to 4 CCR sections 4144, 4147, and 4148. We agree with the commenter that B100 is currently considered to be a blendstock to be blended with diesel. But unlike the commenter, we see no conflict in the regulatory text. Section 95481(a)(2)-(4), when read together, clearly shows that biodiesel is treated as a blendstock to be blended with diesel fuel, thereby resulting in a “biodiesel blend” as defined in section 95481(a)(4). Further, the Staff Report (at II-11 and 12) clearly refers to B100 as a blendstock, not a finished fuel. Therefore, there is no need to modify the definitions or citation to the test method for B100.

Unlike B100, E100 is current subject to ARB motor vehicle specifications under 13 CCR section 2292.3. While it is typically used as a blendstock for gasoline, it can be used as a finished fuel pursuant to 13 CCR section 2292.3. Therefore, we disagree with the commenter’s point with regard to E100.

C-221. Comment: ARB needs to revise the use of “blend stock” for Table 4. We understand the intent but ARB should use a term such as “base fuel” instead of blend stock. This is important because, as written, producers would have to report volumes, carbon intensities, etc. of commodities (i.e. alkylate, reformat, butane, etc.) that are blended to make base fuels that may be subsequently blended with alternative fuels.

We recommend ARB use the term “base fuel” in Table 4 or state for Table 4 that blend stocks reported are not blend stocks that go into CARB, CARBOB, or CARB Diesel unless these blend stocks are actually added at the rack. For example, a regulated party would just report volumes of CARB, CARBOB, Ethanol and other renewable fuels, volumes of CARB diesel, E100, E85.

(WSPA1)

Response: We disagree. The term “blendstock” is a well-established term of art used in the petroleum refining industry. This term was used more than 50 times in the Staff Report and approximately 35 times in the regulatory text. Other than this comment, no serious concerns were raised about this term causing confusion among the stakeholders during the development of the regulation. Moreover, one of the requirements in the definition for “blendstock” in section 95481(a)(10) is that each blendstock must “correspond[s] to a fuel pathway in the California-modified GREET.” Because alkylates, reformates, butane, and other chemical constituents of a blendstock do not have their own fuel pathways in the California-modified GREET, such chemical constituents clearly would not fall within the definition of “blendstock” and the reporting of volumes for those constituents would not be required.

C-222. Comment: “Importer” means the person who owns an imported product when it is received at the import facility in California.

“Import facility” means, with respect to any imported liquid product, the storage tank in which the product was first delivered from outside California into California, including, in the case of liquid product imported by cargo tank and delivered directly to a facility for dispensing the product into motor vehicles, the cargo tank in which the product was imported.

Under the current CBG rules, import facility has a broader definition and allows the use of protocols where a vessel can be considered the import facility instead of a “storage tank”. We’d request similar flexibility under this rule as well.
(WSPA1)

Response: We disagree. Unlike the on-road cargo tank cited by the commenter, ocean-going vessels are typically flagged in countries other than the U.S. Thus, asserting regulatory jurisdiction over such vessels as “storage tanks” for purposes of the LCFS likely would be problematic and subject to legal challenges. The better approach used in the regulation is to treat the landside receiving and storage facility as the “import facility.”

C-223. Comment: WSPA requests more transparency in the Crude Recovery section in the CARBOB and ULSD pathways. In particular, it would be beneficial to disclose the individual Recovery Efficiency factors for the component crudes used to develop the weighted CA Recovery Average of 92.7 percent. (WSPA1)

Response: The CA-GREET model includes details of the calculations. The inputs for petroleum production are based on the mix of crude oil resources for California refineries. The energy inputs were estimated for in-state, Alaskan, and overseas oil production including the mix of energy used in oil production. For California, the energy inputs also included natural gas for steam production for thermally enhanced oil recovery and the associated credit for co-produced electricity. The energy efficiency

and fuel shares were calculated from the weighted average of energy inputs by fuel type. Note that this calculation reflects the total of the energy inputs for oil production and is not the weighted average of the GREET inputs of efficiency and fuel shares.

C224. Comment: In the event that CARB continues to pursue distinguishing crude types, CARB should establish different pathways and default values for different “high intensity” crude pathways, as opposed to grouping them all together as now proposed. Additionally, abatement options such as CCS and efficiency options such as cogeneration should be recognized in the calculation of carbon intensity of crude oil production. (SHELL)

The requirement to consider effective mitigation measures also is reinforced by the August 2007 U.C. Davis analysis of the LCFS. For example, the report includes the following discussion of CCS technologies: In the future, GHG emissions may be reduced by a variety of carbon capture and storage (CCS) technologies that are currently under development (Intergovernmental Panel on Climate Change 2005). (CNAES)

Response: The LCFS does not group all “high intensity” pathways together and does recognize carbon capture and sequestration (CCS) or other methods in the calculation of carbon intensity for “high carbon intensity crude oil” (HCICO). As described in Section 95486(b)(2)(A), the LCFS does require the determination of carbon intensity values for each source crude oil that is not “included in the 2006 California baseline crude mix”. ARB will evaluate data and analyses submitted by regulated parties to determine the appropriate carbon intensity to assign to fuels derived from these crude sources. The regulation also recognizes the use of CCS or other methods used to reduce the carbon intensity for HCICO production and transport.

C-225. Comment: Further, if CARB continues to pursue distinguishing crude types, CARB should clarify how fuels produced from a combination of crude types will be treated under the regulations. For example, there may be situations where the crude oil used to make gasoline at a refinery is 50 percent non-conventional crude and 50 percent conventional crude; in such cases, refiners would be required to report the “average” crude intensity of the fuels produced. From this, it is our understanding that the carbon intensity of the gasoline and diesel produced by a refiner would reflect the relative amounts of non-conventional and conventional crudes. Such a program would result in a unique carbon intensity value for CARBOB and diesel produced by the specific crude diet. Unique carbon intensities, possibly varying daily as a refiner’s crude diet changes, would complicate the transfer of CARBOB’s and diesel through the supply chain. ARB should consider the implications on the fuel supply chain of this policy and develop alternatives, such as a separate accounting method to account for changes in crude carbon intensity, that maintain the ability to effectively transfer fuels through the supply chain. (SHELL)

Response: The LCFS regulation no longer uses the terms “conventional” and “non-

conventional crude”. The calculation of deficits for fuels derived from HCICO was clarified in the Modified Regulation Order as described in the 2nd 15-Day Change Notice.

Post-hearing modifications have added language that would require regulated parties for gasoline, CARBOB or diesel fuel derived from HCICO to calculate deficits relative to the carbon intensity standards in sections 95482 separately for the HCICO and non-HCICO feedstocks (sec. 95486(b)(2)(A)2); these modifications are necessary to ensure the credit calculations accurately reflect the use of HCICO. In connection with the 2nd 15-Day Change Notice, staff further modified the language governing the deficit treatment of CARBOB, gasoline or diesel fuel derived from HCICO. The modifications specify the regulated party must perform a calculation for the base deficit (treating the entire volume of fuel as if it were average CARBOB (for gasoline) or average California diesel (for diesel fuel) and using the average carbon intensity values from the Lookup Tables accordingly) and a separate calculation for the incremental deficit. The incremental deficit would charge the volume derived wholly from HCICO with the actual carbon intensity for that HCICO (determined using the specified procedure). As noted previously, the initial regulated party (i.e., the transferor) would retain the obligation to account for the incremental deficits incurred from the HCICO, while the recipient would get the obligation to account for the base deficits (unless the parties agree otherwise by written contract; modifications to section 95484, “Regulated Parties” provide for such an agreement).

C-226. Comment: We are also concerned that the process that CARB is considering is overly burdensome. As we understand it, a party that petitions CARB to approve an alternative carbon intensity would have to demonstrate that the proposed method for calculating the carbon intensity has been published in a major, well-established, and peer-reviewed scientific journal. It is inequitable for CARB to suggest imposing such a burden on the regulated parties when CARB’s own methodologies and calculations of carbon intensities have not been subject to such a standard of review. (SHELL)

Response: Section 95486(e)(1) of the regulation states:

“(A) For purposes of this regulation, “scientifically defensible” means the method has been demonstrated to the Executive Officer as being at least as valid and robust as Method 1 for calculating the fuel’s carbon intensity.

“(B) Proof that a proposed method is scientifically defensible may rely on, but is not limited to, publication of the proposed Method 2A or 2B in a major, well-established and peer-reviewed scientific journal (e.g., Science, Nature, Journal of the Air and Waste Management Association, Proceedings of the National Academies of Science).”

By its terms, the regulation allows for, but does not require, publication in a peer-reviewed scientific journal to be used as evidence of “scientific defensibility”. We

are developing a nonbinding guidance document to assist stakeholders in navigating the process for establishing carbon intensity values using Methods 2A and 2B. Additional examples of establishing “scientific defensibility” of a fuel’s carbon intensity may be discussed in that guidance document.

C-227. Comment: ARB should allow for individual refiners and importers to establish more accurate carbon intensity values compared to the average values given in the Lookup Table for CARBOB, gasoline, and diesel fuels.

- ARB should allow for refiners to establish individual refining efficiency values for use in calculation of carbon intensity of finished fuels. (SHELL, WSPA1)
- ARB should give credit for use of carbon capture and sequestration at refineries. (SHELL)
- Shell also supports that the same refinery efficiency methodology, which is used for LCFS purposes should be used for AB 32 purposes. That is, the product-specific refining efficiencies should be transparently related to the overall refinery efficiency used in AB 32. (SHELL)

Response: California refineries will be subject to the upcoming AB 32 Cap and Trade Program, so any reductions in GHG emissions from these activities will be counted in that program. The objective of the LCFS program is to stimulate more fundamental changes to the transportation fuel pool, moving towards fuels that meet the much lower carbon intensities needed to meet long-term GHG emissions goals. This objective is best served by identifying single carbon intensity values for almost all CARBOB and diesel fuel, and not allowing revised pathways to be established under Method 2A for CARBOB and diesel fuel with lower carbon intensities. Therefore, within the LCFS all refineries are treated equally and given the same average refining efficiency. Also see the discussion in Section II.B.3. above.

C-228. Comment: Low Energy Refining at Paramount Is Being Unnecessarily and Unfairly Competitively Disadvantaged by the LCFS.

Paramount uses less energy to produce a gallon of CARBOB and diesel than the more complex cracking refineries. Accordingly, the carbon intensity of Paramount's transportation fuels is substantially lower than the average established by the LCFS. The LCFS allows the producers of alternative fuels to establish carbon intensity lower than the "look-up tables" and it is patently unfair to not provide the same opportunity to producers of lower carbon gasoline diesel and gasoline.

The lower energy processing used by Paramount results in substantially lower gasoline and higher asphalt/road oil production than the average U.S. or PADD V (West Coast, Hawaii, and Alaska region refinery as seen in Figure 1 below). The California Energy Commission surveys the California refineries weekly to determine production of gasoline, diesel and other products. The 2006 data in Figure 2 displays the product yield difference between the average California

refinery and Paramount Petroleum

The proposed LCFS requires all producers to use the same baseline for the carbon intensity of its gasoline and diesel fuel. Not only are the actual carbon intensities in the LCFS inaccurate reflections of an average gallon of California produced diesel and gasoline, but by requiring all refiners to use an average carbon intensity, refiners who produce less carbon for each gallon of transportation fuel produced are unnecessarily punished.

Using this methodology, Paramount has a calculated efficiency above 96 percent which is substantially more energy efficient than the average California refinery. Using the average energy intensity factors from the latest 2008 Argonne work on refinery efficiency (http://www.transportation.anl.gov/modeling_simulation/GREET/pdfs/energy_eff_petroleum_refineries-03-08.pdf) combined with Paramount's refinery efficiency, the Paramount product efficiency factors are calculated as 93.7 percent for CARBOB and 95.1 percent for CARB diesel. Even after these efficiencies are adjusted downward by a percent to "California-ize" (the GREET v1.8 model product efficiencies were reduced slightly to account for depentanizer power (for CARBOB) and additional hydrogen (for CARB)), Paramount almost has an 8 percent higher efficiency than the values used to establish the baseline value for LCFS. In other words, Paramount (and other non cracking refineries) use about half the fuel of the average refinery in California to produce a gallon of crude oil based products. Since the refining portion of the lifecycle for CARBOB represents about 14 percent of the CO₂ emitted, the higher efficiency of Paramount's low energy process means Paramount's products will emit about 7 percent less CO₂ than the LCFS baseline. The grams CO₂ equivalent/Megajoule (gCO₂e/MJ) for Paramount's CARBOB and CARB are calculated to be less than 90. As a result, we believe Paramount's products are already more than halfway to the 2020 target goals of 86.3 and 85.2 gCO₂e/MJ as shown in Figure 5 below. This reduced complexity is, as previously documented, a competitive economic disadvantage to Paramount. CARB should not also punish Paramount by ignoring the lower carbon intensity of the gasoline and diesel fuel it produces which results in part from its inability to raise sufficient capital to purchase and erect a more complex cracking unit. It is rare that Paramount's economic disadvantage can be beneficial, but in the case of the LCFS, Paramount's relative simplicity results in less energy consumed per gallon of product.

In addition, to require Paramount to reduce the carbon content of its fuels from a lower starting point than the major oil companies is to further penalize Paramount by grouping it with inefficient high energy heavy oil cracking processes used by all major oil companies. Paramount simply wants to be treated equitably in this LCFS adoption process and wants CARB to note that as a result of its simplistic refining process, it bears very little resemblance to larger complex California refineries. (PP1, PP2)

Response: The Board recognized that refineries may vary in complexity and energy requirements. However, within the LCFS California refineries are assigned the same average efficiency value. Individual refinery efficiencies and improvements to refinery efficiencies will be accounted for within the broader AB 32 program. This distinction in accounting for refinery efficiencies between the two programs is necessary to avoid “double counting” of greenhouse gas emissions credits or debits. This decision will be reviewed as part of the mandated 2011 and 2014 program reviews. See response to Comment C-226.

C-229. Comment: CARB should recognize a process by which individual companies can petition to establish more accurate carbon intensity values compared to the default values for fuels derived from “conventional” crudes, “non-conventional” crudes, and for alternative fuels. CARB should not limit the use of such a process to instances where there is a 10 percent difference between the default carbon intensity and the carbon intensity that would be established through such a process, since any reduction is an improvement that is in line with CARB’s goals of reducing emissions. If CARB intends the 10 percent threshold to apply to the well-to-wheel carbon intensity of the fuel, then CARB appears to be establishing a threshold that is so high that this process is unlikely to ever be used. For example, if the well-to-wheel carbon intensity of CARBOB is 96.2 gCO₂e/MJ, and of that 96.2 gCO₂e/MJ, 20 percent (i.e., 19.2 gCO₂e/MJ) is from the well-to-tank component (which the regulated parties have some ability to affect) and 80 percent (i.e., 77 gCO₂e/MJ) is from the tank-to-wheel component (which is outside the ability of the regulated parties to affect), in order to meet the 10 percent threshold on a well-to-wheel basis, the party petitioning for a unique value would have to demonstrate that they have reduced the carbon intensity of the well-to-tank component from 19.2 gCO₂e/MJ to 9.6 gCO₂e/MJ. Thus to meet the 10 percent well-to-wheel threshold, a regulated party would have to reduce the greenhouse gas emissions of the processes that they can influence by at least 50 percent. This is an extraordinary high threshold, which will create disincentives for firms to take action to reduce emissions. At a minimum, if CARB is going to impose a 10 percent threshold, it should be 10 percent of the portion of the fuel life cycle that the regulated party has the ability to affect. In addition, if a threshold is established, it should not be percentage based, as a percentage basis would arbitrarily establish a lower threshold for fuels that have lower carbon intensities and a higher threshold for fuels that have higher carbon intensities. (SHELL)

Response: This comment addresses many items that are no longer germane to the regulation. First, the LCFS no longer uses the terms “conventional” and “non-conventional” to classify crude oil sources. Second, the regulation does not allow refiners to use Method 2A to obtain a reduced carbon intensity value for CARBOB, gasoline or diesel fuel. Method 2A can only be used for alternative fuels. Third, the LCFS no longer uses a percentage reduction threshold value for an alternative fuel pathway to qualify for a unique carbon intensity value. Instead the regulation requires that the source-to-tank carbon intensity for the fuel pathway be at least 5.00 gCO₂e/MJ

less that the value given in the Lookup Table for the pathway that best reflects the fuel production process. If the fuel pathway meets this criteria and the regulated party is expected to produce more than 10 million gasoline gallon equivalents of the regulated fuel per year, the regulated party can petition for a unique carbon intensity determination using Method 2A. This change to the regulation addresses the criticism discussed in the comment. See responses to Comments C-226 and C-227.

C-230. Comment: Section 5.3.2 of the draft outline states that a single averaged default refinery efficiency will be applied to all refineries. To be consistent with the GREET refinery methodology, there will have to be separate gasoline-specific and diesel-specific refining efficiencies and we ask CARB to clarify that this is indeed the case. Section 5.3.2 also states that obligated parties may submit data to establish a unique value provided that the data shows a substantive difference from the default value. Section 5.3.2.b further provides that CARB will not consider efficiency improvements mandated by other emissions reduction regulations.

Shell supports the proposed process for individual obligated parties to present data to establish unique refinery efficiency values, and suggests that CARB adopt the process outlined in the section (V) above. However, we do not support the restrictions that CARB is proposing on the use of this process. CARB should not limit the use of such a process to “substantive” changes, since any improvement in refinery efficiency should be encouraged. Shell also does not agree with CARB’s proposal to exclude efficiency improvements resulting from other regulatory programs. Regardless of the reason that the refinery efficiency is improved, the fact will be that the carbon intensity of the fuels produced will be lower than they would be without the efficiency improvement. This result is consistent with CARB’s policy goals for the low carbon fuel program and should be encouraged. Furthermore, CARB should consider the potential consequences of not allowing California refineries that are subject to stationary source controls to account for such emission reductions under the LCFS when refineries in other states or countries are not subject to the same stationary source controls. This could result in the shuffling of transportation fuels in and out of California and consequently result in an increase in emissions. CARB also requests comment on whether credits should be allowed if an obligated party makes a substantive reduction in refining emissions through the use of, for instance co-generation and carbon capture and storage technologies, and if so, whether credits should be allowed under the LCFS, AB 32, or both. (SHELL)

Response: The CA-GREET lifecycle assessments do apply separate gasoline and diesel-specific refining efficiencies.

Much of this comment pertains to an early draft version of the regulation and is not germane to the current regulation. Specifically, the LCFS regulation applies the same average refining efficiency values to all refineries and does not allow for individual

obligated parties to establish unique refinery efficiency values. The use of innovative methods, including carbon capture and storage, to reduce GHG emissions and improve efficiency at refineries will be managed and credited under the broader AB 32 program. In order to avoid “double counting” of the emission reduction benefits derived by use of these technologies, these methods will not receive credit under the LCFS regulation. See response to Comment C-226.

C-231. Comment: The draft regulations propose to treat “non-conventional” crudes differently, and separately, from “conventional” crudes. In particular, in section 95425, the draft regulations specify that conventional gasoline and diesel fuel produced from conventional crudes must be assigned industry average carbon intensity values, while such fuels produced from non-conventional crudes are presumed to be 10 percent more carbon intensive.

We appreciate CARB’s willingness to include an opt-in process for “non-conventional” crudes. However, we have several concerns with the process that CARB has proposed. CARB establishes a presumption that fuels produced from non-conventional crudes are at least 10 percent more carbon intensive than fuels produced from conventional crudes, and establishes a process for rebutting the presumption. CARB has not yet published the default value for unconventional crudes, so it is not possible to provide comments on the default value at this time. The draft regulations imply, however, that CARB intends to group all unconventional crudes together and establish a single default value for all non-conventional crudes. In our view, that would be inappropriate. Just as CARB establishes different pathways for ethanol, CARB should establish different pathways and default values for different non-conventional crude production pathways. For example, Shell believes that the GHG emissions from a raw bitumen blend vs. an upgraded non-conventional crude are very different.
(SHELL)

Response: Much of this comment pertains to an early draft version of the regulation and is not germane to the current regulation. First, the LCFS no longer uses the terms conventional and unconventional to classify crude oil sources. Second, ARB will not establish a single default value for unconventional crudes. All crude oil sources that are not “included in the 2006 California baseline crude mix” must be evaluated individually when used in the California fuel market and each will be assigned an appropriate carbon intensity. Those sources with a production and transport carbon intensity similar to the average (less than or equal to a threshold of 15 gCO₂e/MJ) will be classified as “non-high carbon intensity crude oil” sources and fuels derived from these sources will also receive the average carbon intensity value shown in the Lookup Table. Those sources with a production and transport carbon intensity greater than 15 gCO₂e/MJ will be classified as “high carbon intensity crude oil” sources and fuels derived from these sources must use the carbon intensity for their specific pathway as determined by Method 2B. Producers of “high carbon intensity crude oil” may use control measures, such as carbon capture and sequestration or other methods, to reduce the carbon intensity for production and transport to 15 gCO₂/MJ or less and consequently receive

the average carbon intensity value from the Lookup Table.

C-232. Comment: And, lastly, CARB should revise the definitions of “conventional crude oil” and “non-conventional crude oil. In section 95427, non-conventional crude oil is defined by either the type of formation in which the energy resource is extracted (oil sands, tar sands, oil shale) or by a production process gas-to-liquids or coal-to-liquids (GTL or CTL). GTL and CTL processes do not produce oil or a feedstock that requires further processing at a refinery and thus, it is inappropriate for CARB to include gas-to-liquids and coal-to-liquids in the definition of “non-conventional crude oil.” In addition, the definition separately lists “oil sands” and “tar sands.” Are “oil sands” different from tar sands or are these intended as synonyms? (SHELL)

Response: This comment pertains to an early draft version of the regulation and is not germane to the current regulation. The LCFS regulation no longer uses the terms “conventional”, “non-conventional”, “oil sands”, “tar sands”, “coal-to-liquids”, or “gas-to-liquids” to classify crude oil sources.

C233. Comment: The carbon intensity of some Canadian oil sands crude has been determined by independent analysis to be less than many crude oil sources considered part of the California baseline crude mix. (CAPP1, AE1, AE2)

Response: ARB has not performed an evaluation of Canadian oil sands since these crude sources are not part of the 2006 California baseline crude oil mix. However, information provided by these independent studies may be used by ARB staff. When submitted to ARB by a regulated party, this information will be evaluated as part of the Method 2B process to determine the pathway specific carbon intensity of fuels derived from oil sands crude.

C-234. Comment: The upgrading of some of oil sands production in Alberta produces light crude that is particularly suited for refining into transportation fuels. The refining emissions required to complete the production of transportation fuels from upgraded oil sands are lower than those associated with other crude oil feedstocks. Any comparison of crude supplies at the refinery gate has to take this into account to properly reflect life cycle intensities. (CAPP1, AE1, AE2)

Response: ARB has not performed a lifecycle assessment of Canadian oil sands for the LCFS. We recognize that upgrading of heavy crude produces lighter crude which can result in somewhat lower refinery emissions. Within the LCFS structure, credit is not granted for these reduced refining emissions as all refineries are given the same average refining efficiency irrespective of the crude oil source. Improvements in refining efficiency will however be recognized by the broader AB 32 program. This distinction is necessary to prevent double counting of refinery efficiency improvements under the two programs. See responses to Comments C-227 and C-228.

C-235. Comment: As the LCFS is a complex regulation, we are concerned about the

possible difficulties this will create for implementation. For example, the GHG emissions associated with oil sands production vary by facility and crude oil is often blended throughout the North American pipeline system, mixing crude oils derived from different sources. This makes tracking crude oil blends used by refiners to their source a particular challenge. (GOVTCANADA)

Response: In most cases, refiners enter into contracts with specific crude oil producers and therefore the tracking of crude oil to the source is simple. However, in some limited cases it may be difficult to track crude oil to individual sources. ARB will work with refiners and importers to establish protocols to best determine the sources of crude oil used to make fuels consumed in California.

C-236. Comment: The U.S., and particularly California, offers an efficient market destination for Canadian crudes considering supply proximity and economics. Furthermore, most U.S. refineries (particularly in California) are configured to run on heavy crude and existing supplies of heavy California crudes are declining. Thus, sourcing appropriate substitute supplies for California refineries will be necessary to maintain refinery efficiency and competitiveness. If sufficient alternative crudes cannot be sourced, the consequence is likely to be under-utilization of California refineries resulting in less efficient production of transportation fuels and the need to import finished products. (SHELL)

Response: The LCFS does not prohibit the use of crude oil sources which are not part of the 2006 California baseline mix. The LCFS requires regulated parties to determine appropriate carbon intensity values for fuels derived from these sources if they are used in California.

Recognizing that the focus of the LCFS regulation on greenhouse gas emissions may result in some unanticipated consequences, the Board directed ARB staff to conduct comprehensive program reviews in 2011 and 2014. Although we do not believe that the LCFS will result in under-utilization of California refineries, we will address this possibility during the program reviews.

C-237. Comment: Fuels derived from all crude oil sources (including Canadian oil sands) should be assigned the same average carbon intensity value from the Lookup Table. (SHELL, WSPA1, BP1, CAPP1, CAPP2, GOVTCANADA, CNAES, CCG)

ARB should review these average carbon intensity values periodically and make adjustments, if necessary, to compensate for changes in the carbon intensity of crude oil. (SHELL)

Response: The rationale for the LCFS regulation's treatment of carbon intensity of CARBOB, gasoline and diesel fuel – including CARBOB, gasoline and diesel fuel derived from high carbon intensity crude oils not included in the 2006 California baseline crude mix – is set forth in Section II.B.3.

The Board directed ARB staff to conduct comprehensive program reviews in 2011 and 2014 and return to the Board with regulatory changes if necessary. Section 95486 “Determination of Carbon Intensity Values” of the regulation will be a topic of this program review.

C-238. Comment: The LCFS is/may be discriminatory against Canadian oil sands and other sources of unconventional crude oil. Oil sands crude has a carbon intensity similar to or less than many “conventional” crude oil sources including some crude sources which are “included in the 2006 California baseline crude mix”.(CAPP1, GOVTCANADA, CNAES, CCG, AE1, AE2)

Discrimination against Canadian oil sands crude oil may be perceived as creating an unfair trade barrier and could be contrary to international trade obligations of the United States. (GOVTCANADA)

Response: The LCFS does not discriminate against any source of crude oil. The average carbon intensity values for CARBOB, gasoline, and diesel shown in the Lookup Table are calculated using a weighted average of fuels derived from 2006 California baseline crude oil sources. Assigning an average carbon intensity value to fuels derived from California baseline crude oil sources will prevent shuffling of these crudes to distant markets. All other crude oil sources that are not “included in the 2006 California baseline crude mix” must be evaluated individually when used in the California fuel market. Those sources with a production and transport carbon intensity similar to the average (less than or equal to a threshold of 15 gCO₂e/MJ) will be classified as “non-high carbon intensity crude oil” sources and fuels derived from these sources will also receive the average carbon intensity value shown in the Lookup Table. Those sources with a production and transport carbon intensity greater than 15 gCO₂e/MJ will be classified as “high carbon intensity crude oil” sources and fuels derived from these sources must use the carbon intensity for their specific pathway as determined by Method 2B (or the Lookup Table if a pathway assessment for a similar crude source has already been completed). Producers of “high carbon intensity crude oil” may use control measures, such as carbon capture and sequestration or other methods, to reduce the carbon intensity for production and transport to 15 gCO₂/MJ or less and be assigned the average carbon intensity value from the Lookup Table.

The LCFS therefore differentiates between crude oil sources that were used in significant quantities in California in 2006 (e.g. “included in the 2006 California baseline crude mix”) and those crude sources that were not used in significant quantities in 2006. Crude sources which fall into this latter category are treated equally as each must undergo a pathway specific carbon intensity determination as they enter the California market. The only “high carbon intensity crude oil” that is included in the 2006 California baseline crude mix and therefore qualifies for the default average carbon intensity values under Method 1 is California crude oil produced using thermal enhanced oil recovery processes. The estimated carbon intensity from production and transportation of this crude oil is approximately 19 gCO₂e/MJ. We do not believe that this crude oil and

Canadian oil sands crude oil are “like products” because the production facilities situated in California will be subject to the AB 32 cap and trade program that is scheduled to start in 2012. We expect that the cap and trade program will result in either application of technologies at the production facilities that reduce the carbon intensity below 15.00 gCO₂e/MJ, or the acquisition of credits from other GHG emission reduction activities that achieve the equivalent to such a reduction in carbon intensity. The California cap and trade program will not apply to out-of-state “high carbon intensity crude oil” production facilities, although there is a possibility it could be part of a broader regional program.

The Board has directed ARB staff to conduct comprehensive program reviews in both 2011 and 2014. The crude oils considered to be part of the California baseline mix and the potential change in the carbon intensity of crudes included in the California baseline mix would necessarily be evaluated during these and subsequent program reviews and addressed via regulatory change if deemed necessary. Additionally, following enactment of the AB 32 Cap and Trade Program, ARB would consider program modifications which recognize equivalent, enforceable emissions reductions resulting from carbon management programs enacted by out-of-state governments. But ARB believes that the issue raised by the commenters is particularly significant, and in the coming year ARB may consider whether near-term revisions to the regulation addressing this issue are appropriate.

C-239. Comment: Differentiating or discriminating against Canadian oil sands crude oil will result in:

- Challenges to improving U.S. energy security. (SHELL, CAPP1, GOVTCANADA, CNAES)
- Redirection or shuffling of crudes to more distant markets and an increase in greenhouse gas emissions. (SHELL, WSPA1, CONOCO, CAPP1, GOVTCANADA, CNAES)

Response: Please see the response to Comment C-238.

The LCFS is designed to decrease California’s dependence on crude oil while increasing the use of alternative fuels including ethanol, biodiesel, natural gas, electricity, etc. Therefore, on balance, we believe that the LCFS will improve national energy security.

However, the primary intent of the LCFS is not to improve national energy security but rather is to reduce greenhouse gas emissions associated with production and use of transportation fuels in California. As such, we believe that it is critical to characterize crude oil sources using an accurate evaluation of their carbon emissions. Only by doing so can the regulation be successful in promoting the adoption of lower carbon intensity production methods and meet its stated goal of reducing the carbon intensity of California’s transportation fuels by 10 percent. We agree that California’s LCFS, operating in isolation, may temporarily increase the potential for crude oil shuffling.

However, as LCFS regulations become more widely adopted by state and national governments the potential for crude shuffling will be greatly diminished.

C-240. Comment: Differentiating or discriminating against Canadian oil sands crude is unnecessary because Canada has committed to reduce greenhouse gas emissions associated with oil sands production through regulations at the federal and provincial level. (CAPP1 30, CAPP2, CNAES)

Response: Please see the responses to Comments C-238 and C-239.

The LCFS was adopted by the Board as a discrete early action measure pursuant to AB 32. The broader cap and trade provisions of AB 32 are still being developed. Eventually, the LCFS and the Cap and Trade programs within AB 32 will be integrated. Following enactment of the AB 32 Cap and Trade Program, ARB would consider LCFS modifications which recognize equivalent, enforceable emissions reductions resulting from carbon management programs enacted by out-of-state governments.

C-241. Comment: Differentiating or discriminating against Canadian oil sands crude oil is unnecessary because the carbon intensity of all mainstream crude oil sources falls within a narrow range and the majority of the emissions occur during fuel combustion. (CAPP1, CNAES, CCG, AE1, AE2)

Response: Please see the responses to Comments C-238, C-239, and C-240.

With regard to the carbon intensities of crude sources, we do not agree that all mainstream crude oil production methods have similar carbon intensities. Our calculations show that carbon intensities for mainstream crude oil production methods range from about 4 to more than 20 gCO₂e/MJ. Requiring all crude sources not part of the 2006 baseline mix to be evaluated individually will help to ensure that increased use of “high carbon intensity crude oil” production methods are accurately accounted for within the regulation. It will also provide greater incentive for these producers to reduce emissions through CCS or other methods.

C-242. Comment: Yet another reason to avoid a discriminatory LCFS is that it would be extremely difficult to administer fairly and effectively. Many refinery feedstocks are produced, transported, stored, blended and otherwise altered in ways that may not be readily apparent to those conducting the assessments or auditing the work of producers, brokers and other types of vendors. In this system, domestic producers and those from countries with comprehensive reporting systems would be disadvantaged. Similarly, the focus on the carbon footprint alone would work to the disadvantage of feedstocks with low sulfur content or other environmental advantages but higher emissions of greenhouse gases. These aspects of the proposed system are likely to result in undesirable outcomes such as discrimination in favor of products from foreign countries with substandard environmental or human rights policies, and against products that have other desirable environmental attributes or emanate from countries with highly

developed reporting systems. (CNAES)

Response: Please see responses to Comments C-238, C-239, and C-240.

In some limited cases it will be difficult to track crude oil to individual sources. ARB will work with refiners and importers to establish protocols to best determine the sources of crude oil used to make fuels consumed in California.

We recognize that the focus of the regulation on greenhouse gas emissions may result in some unanticipated consequences. Because of this, the Board has directed ARB staff to present a work plan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation. These sustainability provisions will likely address many environmental and social consequences of fuel production which are not specifically addressed through focus on greenhouse gas reduction.

C-243. Comment: Further, an arbitrary distinction between conventional and unconventional categories is an over-simplification of the suite of petroleum-based refinery feedstocks currently available. The global reality is that feedstocks in general are becoming heavier and sourer regardless of whether they are derived from so-called conventional or nonconventional sources. The past decade has seen significant changes in this regard that can be expected to continue even more markedly over the period when the LCFS takes effect. Many refineries currently are undergoing substantial modification to process these heavier feedstocks. (CNAES)

Response: The LCFS regulation does not differentiate between conventional and unconventional crude oil sources. The terms conventional and unconventional are no longer used in the regulation. The regulation differentiates between crude oil sources that are “included in the 2006 California baseline crude mix” and those that are not. ARB is committed to an accurate accounting of carbon intensity values for both petroleum-based and alternative fuels. We agree that the carbon intensity of crude sources may change over time. Within the LCFS framework, crude sources not part of the 2006 California baseline crude mix are required to be evaluated individually as they enter the California market and be assigned an appropriate carbon intensity value. Furthermore, the Board has directed ARB staff to conduct comprehensive program reviews in both 2011 and 2014. The potential change in the carbon intensity of crudes included in the California baseline mix will be evaluated during the program reviews and addressed via regulatory change if deemed necessary.

C-244. Comment: Rather than attempting to regulate the carbon emissions associated with the production of crudes through the low carbon fuels standard, CARB should recognize that the carbon intensity of crude oil is better managed at the production source through point source regulations (cap and trade system). Furthermore, when determining the carbon intensity of fuels, the emission reductions resulting from such point source emission control measures

should be accounted for and credited under CARB's regulations to avoid imposing a double obligation on the fuels. (SHELL)

All fuels, fuel components, and feedstocks need to be treated equitably (this should include different sources of crude oil such as Canadian oil sands). The California program should fully recognize and consider any controls and carbon management practices that are imposed at the production site in other countries. (CONOCO)

Full credit for all deployed mitigation measures should be allowed, including offsets and/or carbon credit purchases or fees. (CNAES)

Response: See responses to Comments C-237, C-238, and C-239. The rationale for the LCFS regulation's treatment of carbon intensity of CARBOB, gasoline and diesel fuel – including CARBOB, gasoline and diesel fuel derived from high carbon intensity crude oils not included in the 2006 California baseline crude mix – is set forth in Section II.B.3.

C-245. Comment: Discrimination against petroleum-based fuels derived from unconventional sources is not necessary to achieve the purposes of AB 32 and would in fact be counterproductive. Discouraging the import of fuels into California derived from unconventional sources would have an inflationary effect on fuel prices in California, as these cost effective North American fuels would not be available. The adverse economic impacts would affect low-income citizens disproportionately, an effect that AB 32 expressly seeks to prevent. While the legislation states a goal of contributing to worldwide greenhouse gas reductions, a discriminatory LCFS would not assist in attaining that goal. Fuels barred from California would simply be sold elsewhere, to other states or foreign countries where controls may be more lax and emissions from fuel transportation increased. The California economy would suffer, but worldwide emissions would not be reduced and in some cases would be increased. This is precisely the situation that AB 32 and AB 1007 seek to avoid, in requiring a regulatory program “that is equitable, seeks to minimize costs and maximize total benefits,” and “minimizes the economic costs to the state” (secs. 38562(b)(1), 43866(b)(2)).

AB 32 calls for a program that is “feasible . . . complementary, non-duplicative, and can be implemented in an efficient and cost-effective manner” (sec. 38561(a)). The program also must “minimize the administrative burden of implementing and complying with these regulations” (sec. 38562(b)(7)). A LCFS that discriminates against North American unconventional resources would not be consistent with these requirements.

If a discriminatory standard is retained, it is essential that the host of national and international mitigation measures potentially employed is considered, both for the reasons discussed above and because various provisions of AB 32 require consideration of mitigation measures. On the basis of the prior drafts of the

LCFS and underlying materials, the Center understood that full credit would be given for actual mitigation measures associated with crudes supplied to California refineries. We now understand that at the March 27, 2009 LCFS workshop, CARB staff clarified that no credit would be given for compliance with GHG reduction programs outside of California.

Such an approach would constitute a blatant violation of AB 32. For example, Sections 38561 and 38562 include the following requirements, among others:

- The state board must consider all relevant information pertaining to greenhouse gas emissions reduction programs in other states, localities, and nations, including the northeastern states of the United States, Canada, and the European Union;
- The state board must identify opportunities for emission reductions measures from all verifiable and enforceable voluntary actions, including, but not limited to, carbon sequestration projects and best management practices;
- The regulations must be designed in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California, and encourages early action to reduce greenhouse gas emissions;
- The state board must consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health.

None of these requirements would be satisfied by refusal to consider out of state mitigation measures. In addition, the earlier requirements of AB 1007 provide that “full fuel-cycle assessment means evaluating and comparing the full environmental and health impacts of each step in the life cycle of a fuel . . .” (sec. 43867(b), emphasis added). No full and complete assessment of such impacts could fail to consider effective mitigation and other emission reduction measures. (CNAES)

Response: See responses to Comments C-237, C-238, C-239, C-241, and C-242.

The LCFS was adopted by the Board as a discrete early action measure pursuant to AB 32. The broader cap and trade provisions of AB 32 are still being developed. Eventually, the LCFS and the Cap and Trade programs within AB 32 will be integrated. Following enactment of the AB 32 Cap and Trade Program, ARB would consider LCFS modifications which recognize equivalent, enforceable emissions reductions resulting from carbon management programs enacted by out-of-state governments.

C-246. Comment: ARB should account for potential changes to the average carbon intensity values for CARBOB, gasoline, and diesel fuels resulting from the trend toward production and use of heavier crude oil. (UNE2, MDSA)

Response: ARB is committed to an accurate accounting of carbon intensity values for both petroleum-based and alternative fuels. Over time there is potential for the carbon intensity of crude sources that are “included in the 2006 California baseline crude mix”

to increase. This increase may occur as production from these sources shifts from lower carbon intensity primary and secondary methods to higher carbon intensity methods or if new fields are discovered that require high carbon intensity production methods. The Board directed staff to perform comprehensive evaluations of the program in 2011 and 2014. This potential shift in production intensity of baseline crude oil will be evaluated during these and subsequent program reviews and addressed via regulatory change if deemed necessary.

C-247. Comment: It is clear that a portion of US military expenditures and associated GHG emissions are related to the protection of oil exports from the Middle East. (UNE2)

Response: The Board has directed ARB staff to convene an Expert Workgroup to refine and improve the land use and indirect effects analysis of transportation fuels. Although ARB does not believe that it is appropriate to include emissions associated with military activities in the Middle East in the lifecycle analysis of petroleum based fuels, the Board will seriously consider input from the Expert Workgroup on this matter.

C-248. Comment: The LCFS requires the Board to achieve annual reductions in carbon intensity measured against a baseline or reference scenario in which there is continued reliance on gasoline and diesel fuels. The Staff Report calculated the carbon intensity of California gasoline (CARBOB) based on the carbon intensity of average rather than the marginal source of crude oil delivered to California refineries. The Staff Report used an assumption that crude oil recovered in California represented 40 percent of the all crude delivered to California refineries. The Staff Report's reliance on the average carbon intensity of delivered crude oil stocks masks market mediated impacts. That is, in the current market, marginal crude oil supplies are being obtained from sources like shale and tar sands in Canada. Such supplies have much heavier carbon intensity than other supplies of crude oil delivered to California.

Novozymes believes that the LCFS reference case should be based on the carbon intensity of the marginal supplies of oil that would be displaced by the LCFS policies mandating lower carbon fuels. The size of California's oil market is sufficiently large that LCFS, when implemented, should have a depressive effect on crude oil prices in California and world-wide. This should have the marginal effect of displacing the most expensive sources of crude oil, which may happen to be carbon-heavy tar sands from Canada. The Staff Report's approach dilutes this price mediated effect by calculating the reference case carbon intensity value of gasoline using the average supplies of crude oil delivered to California refineries. Consistent with its incorporation of market-mediated effects in calculating ILUC, the Board should consider requiring that staff measure the carbon intensity of CARBOB using the marginal supplies of crude oil on the world market for determining the reference case carbon intensity value. Recalibrating the reference case's carbon intensity will better reflect the GHG reductions achieved by biofuels. (NOVOZYM)

Furthermore, oil from Canadian tar sands is already moving into US commerce. It is an alternative fuel for the transportation sector, like renewable ethanol. Since both are emerging to replace declining crude oil production in the Northern Americas, including Mexico, it is more accurate to compare the FFCCF of ethanol to the FFCCF of reformates as well as the FFCFF of tar sands, with and without ILUC included in the calculus. (BCC2)

Response: California Executive Order S-01-07 sets the goal of a 10 percent reduction in the carbon intensity of transportation fuels used in California by the year 2020. Therefore, the reference case used for the compliance schedule must be derived from the current CA average crude mix. We realize that the average carbon intensity of California crude may increase over time as crude sources become heavier. This potential shift in average crude carbon intensity will be evaluated during the program reviews conducted in 2011 and 2014 and addressed by regulatory change if deemed necessary.

The Board directed ARB staff to create an Expert Workgroup to refine and improve the land use and indirect effects analysis of transportation fuels. The indirect effect associated with alternative fuels displacing marginal crude rather than CA average crude is a topic that will likely be addressed by the Expert Workgroup. ARB will seriously consider the findings of the Expert Workgroup on this matter. This topic will also be considered in the mandated program reviews occurring in 2011 and 2014.

C-249. Comment: We are not sure that ARB is applying the principle of indirect effects enforcement in a balanced and consistent way. For example, ARB staff has made clear their inclination to debit all crop-based ethanol for ILUC, irrespective of the type or location of the land used for production. However, on the subject of tar sand petroleum use by oil companies, ARB staff has implied only that oil companies will be debited if they use tar sands in California. Put another way, the penalty for biofuels is automatic while the penalty for oil can be avoided by redistributing its product. This creates obvious compliance inequities, but also questionable climate accounting in the marketplace. Oil companies will simply use lighter crude in California to escape penalty under the LCFS. But this decision will short supply of light crude elsewhere and increase the demand for tar sands and other resource intensive crude with obvious climate impacts. Requiring oil companies to account for tar sands use abroad is the definition of a market-mediated effect. Yet ARB seems more inclined to enforce market-mediated effects against ethanol, for land use change, than indirect effects against oil companies for heavy crude and tar sands. (NFA1)

Response: The LCFS will not debit crop-based biofuels for land use change emissions irrespective of the type or location of land used for production. In Resolution 09-31, the Board directed staff to work with interested stakeholders to develop criteria and a list of specific biofuel feedstocks that are expected to have no or inherently negligible land use effects on carbon intensity and propose amendments, if appropriate, to the regulation

resulting from this analysis by December 2009. These criteria and list of feedstocks will be included as part of a guidance document prepared by ARB to streamline the application process for a carbon intensity determination under Method 2. The overriding criterion that must be met before a fuel can be included on this list is that production of its feedstock must not compete with the production of food. The specific criteria are expected to include the following:

- Fuel feedstock crops grown on abandoned farmland that is currently degraded. Crops grown in this way do not compete with food crops, but they could also prove to be environmentally beneficial. In addition to their potential to improve wildlife habitat and water quality, perennial feedstock crops could increase soil carbon sequestration.
- Crop residues. Although crop residues increase soil fertility, decrease erosion, and improve soil carbon stores when left on fields, some residues can be removed without compromising these benefits. The removable fraction is capable of supporting the production of significant quantities of biofuels.
- Double and mixed cropping. Biofuel crops that can be grown and harvested between existing food cropping cycles (and which do not interfere with those cycles) meet the criterion established above. The same is true for crops that can be grown along with food crops (such as between food crop rows).

ARB acknowledges that California's LCFS, enforced in isolation, may temporarily increase the potential for crude oil shuffling. However, as the LCFS regulation becomes more widely adopted by other governments the potential for crude shuffling will be greatly diminished. Moreover, the potential for fuel shuffling is not limited to petroleum-based fuels. It is highly likely that supplies of ethanol with the lowest carbon intensity will be sent to California with the remaining "high intensity" ethanol being sold outside of California. The LCFS does not account for this market-mediated effect which obviously benefits producers of low carbon intensity ethanol but does not result in reductions in greenhouse gas emissions on a global scale. However, as the LCFS regulation becomes more widely adopted the potential for ethanol shuffling will also be greatly diminished. See response to Comment C-247.

C-250. Comment: It is also of significant concern that the ISOR proposes that petroleum is only penalized for getting dirtier if its carbon intensity increases by more than a certain value (~ 15 percent) compared to the California average. This means that oil companies can use more carbon intensive crude as the regulation progresses without penalty. From a policy perspective, it is clear that if a particular fuel's carbon profile increases then it should be held accountable and penalized accordingly. This does not mean that the baseline targets need to be diluted. The LCFS should call for 10 percent reduction from today's baseline, and still require oil companies that get worse over time to hit the same carbon intensity target. Put another way, like biofuel companies, oil companies should be debited for the feedstock they use. (NFA2)

Response: ARB is committed to an accurate accounting of carbon intensity values for both petroleum based and alternative fuels. The average carbon intensity of California

baseline crude may increase over time as crude sources become heavier. To address this, the Board directed staff to conduct comprehensive program reviews in 2011 and 2014. This potential shift in average crude oil sources will be evaluated during these and subsequent program reviews and addressed by regulatory change if deemed necessary.

C-251. Comment: To successfully address the climate change component of the perfect storm, it is imperative that coal-to-liquids, tar sands-derived fuels, and shale oil-derived fuels not be a part of the strategy. All of these unconventional fossil fuels will increase emissions of greenhouse gases relative to gasoline. They are not a sustainable solution and do not represent even a bridge to a more sustainable future. Although coal-to-liquids and shale oil do address energy independence and energy security issues, they do not address climate security and therefore do not represent a sustainable future fuel option. (ICM3)

Comment: The low-carbon fuels standard should provide a specific penalty for fuels with an extra-high impact on carbon emissions, above and beyond that of conventional oil, including ethanol and gasoline derived from Canada's "tar-sands" oil. Only a true and accurate lifecycle assessment of carbon impact can accurately guide the CARB standard, and such an impact must exclude and specifically discourage agro-fuels and tar sands. (STEITZ)

Comment: This LCFS should also avoid the use of more environmentally damaging fuels derived from tar sands, oil shale, and coal. (CVAQ)

Comment: Ban gasoline and diesel produced from Canadian tar sands crude oil and feedstocks in California, and limit, then phase out other heavy crude oils, just as coal is being phased out in the electricity sector. (CBE3)

Response: The LCFS should not exclude the use of any fuels. All fuels are allowed to compete in the marketplace. What the LCFS does is introduce into the marketplace the additional consideration of lifecycle greenhouse gas emissions impacts. Those fuels which are both economical to produce and also have low greenhouse gas emissions will compete well under the LCFS. Those fuels with large lifecycle greenhouse gas emissions may still be used, but any increase in emissions relative to the compliance standard must be compensated for by increased use of fuels with low lifecycle greenhouse gas emissions. In summary, the LCFS is designed not to dictate which fuels can or cannot be used but rather is designed to introduce the additional consideration of lifecycle greenhouse gas emissions into the decision-making process.

The carbon intensity of crude oil sources that are not part of the 2006 California baseline crude mix will be evaluated as they enter the California market. Treatment of these crude sources is specified in Section 95486(b)(2)(A) of the LCFS regulation. See also response to C-257.

C252. Comment: Keith Kline (co-author of this comment letter) has spent over twenty years, the majority of his professional career, working on international programs to protect biodiversity, promote sustainable development and reduce deforestation. In that capacity, Mr. Kline witnessed tremendous land conversion impacts, direct and indirect, of oil and gas exploration activities in developing nations. These are driven by world demand for petroleum products but are overlooked in the proposed CARB rule. Such resource extraction activities may very well be among the most significant factors contributing to the accelerated loss of natural habitat in the remaining forest zones of our planet. (KLINE)

Response: ARB continues to study potential direct and indirect effects associated with the production of all fuels subject to the LCFS. Other than land use change emissions for crop-based biofuels, no significant indirect effects that result in large greenhouse gas emissions have been identified that would substantially affect the LCFS framework for reducing the carbon intensity of transportation fuels.

The topics of land use change and other indirect effects of petroleum based fuels will be addressed by the Expert Workgroup being convened by direction of the Board. The Board will seriously consider any recommendations made on these topics by the Expert Workgroup.

C-253. Comment: One important indirect petroleum effect that must be acknowledged is the long-term impact of not immediately beginning to diversify away from fossil fuels. Failure to transition away from fossil fuels will result in increased demand for conventional oil, which depletes those sources faster today and accelerates the need for higher greenhouse gas fossil hydrocarbons (e.g. tar sands and oil shale) tomorrow. (ABENGOA)

Response: The LCFS is structured properly to stimulate the production and use of alternative low-carbon fuels which will diversify the transportation fuel market away from fossil fuels. These alternative low-carbon fuels may include biofuels, low-carbon electricity, and landfill or digester natural gas. Although the regulation does not restrict the use of any crude oil source, use of petroleum fuels with an assigned carbon intensity value greater than the average will necessitate the use of even greater amounts of low-carbon alternative fuels in order for regulated parties to meet the compliance standard. This in turn leads to even greater diversification away from fossil fuels.

C-254. Comment: We ask that the Board support CARB's efforts to address high-carbon intensity fuels by including provisions to differentiate these fuels. We also request in particular, that specific pathways for tar sands, oil shale, and liquid coal continue to be developed and released for public review and comment. For example, the current default assumptions in the GREET lifecycle model for tar sand pathways are based on secondary references and non-public data sources. We support CARB's continued efforts to update these estimates in an open and transparent manner. Doing so will allow for more accurate assessments to be

made and the correct market signals to be placed on both low and high-carbon intensity fuels. (NRDC2, NRDC3, NRDC3)

Response: When crude oil sources which are not part of the 2006 California baseline crude mix enter the California market, ARB will evaluate the pathway lifecycle assessments submitted by regulated parties using the Method 2B process. This review process will be conducted in an open and transparent manner.

C-255. Comment: We recommend that ARB thoroughly analyze the full lifecycle for each individual grade of feedstock including all dirtier crudes, and that the LCFS should not give any credit for use of CCS technologies. (CERA1)

Response: The Board approved the lifecycle evaluation of crude oil sources included in the 2006 California baseline crude mix. As new crude oil sources enter the California market, pathway lifecycle assessments submitted by regulated parties using the method 2B process will be evaluated and appropriate carbon intensity values will be assigned to fuels derived from these crude sources. This review process will be conducted in an open and transparent manner. ARB believes that it is appropriate to credit verifiable emissions reduction efforts undertaken by crude oil producers. The use of carbon capture and sequestration or other GHG emission reduction methods by these crude oil producers will be considered in assigning the appropriate carbon intensity value.

C-256. Comment: Provided that agrofuels are excluded, the LCFS could substantially reduce California's carbon emissions by penalizing oil companies for refining raw materials that have a higher carbon footprint than that of conventional oil. The dirtiest of these raw materials include synthetic crude oil made from sticky bitumen mined from Canada's tar sands.

So I want to thank again CARB and the Air Resources Board for changing the market to provide real incentives for a real step in the right direction and encourage you to go further by imposing stiffer penalties on tar sands and industrial agrofuels. (RAN1, RAN2, RAN3, CAPOZ)

Response: The LCFS is a performance-based regulation and attempts to assign appropriate carbon intensity values to all fuels. The LCFS does require the calculation of pathway specific carbon intensity values for fuels derived from crude oil sources which are not part of the 2006 baseline crude mix. Section 95486(b)(2)(A) of the LCFS regulation specifies the requirements for determining carbon intensity values for CARBOB, gasoline, and diesel fuel derived from these crude oil sources.

C-257. Comment: The AQMD staff strongly recommends that CARB staff track the quality of crude oil, rather than simply assume that all conventional crude quality will remain constant through the duration of the regulation. Trends in declining quality and resulting carbon intensification of conventional crude oil feedstocks should not be overlooked in the regulation. Some refiners assert that any effort to differentiate conventional crude quality will be ineffectual due to global

“reshuffling”. However, important economic and market signals will result by including within the LCFS an adjustment for the API gravity of individual crude shipments. By placing a direct market signal on the carbon content of all feedstocks, the CARB carbon intensity regulation will go a long way in helping rationalize the market to supply finished products with net lower carbon intensity. This principle will have particular importance as a precedent once a federal carbon intensity standard is promulgated. While the differences in upstream crude quality may be relatively small (at least in the short term), the key lesson of the GREET model and other well-to-wheel analyses is that small differences, when multiplied through the entire fuel pathway reflecting billions of gallons annually, can have very disproportionate carbon implications.

Anything short of addressing the carbon intensity of all crude sources would not be a “gold” standard; a bifurcated system which assumes constant conventional crude quality, in contrast, is more akin to a “brass” standard. The decline in crude oil quality was acknowledged several years ago by Jean-Luc Guiziou, President of Canadian Operations for France’s major oil company, Total:

“We have to accept the reality of geoscience, which is that the next generation of oil resources will be heavier.”

For this reason, the AQMD staff agrees with CARB's intent to breakout tar sands based crude feedstocks. At the same time, it is essential that all crude sources be treated equitably by tracking and accounting for the specific API gravity or carbon content of all fossil feedstocks used by refineries to produce transportation fuels sold in California. (SCAQMD1, SCAQMD2, SCAQMD3)

Response: The use of a surrogate measure such as API gravity to assign carbon intensities of fuels derived from different crude oil sources is unnecessary.

To avoid shuffling of existing crude oil sources, ARB decided to include an average carbon intensity value for crude oil sources which make up a significant portion of the traditional California basket of crudes. These crude oil sources are differentiated as being “included in the 2006 California baseline crude mix”. Over time there is potential for the carbon intensity of crude sources that are part of the 2006 California baseline crude mix to increase. This increase may occur as production from these sources shifts from lower carbon intensity primary and secondary methods to higher carbon intensity methods or if new fields are discovered that require high carbon intensity production methods. The Board directed staff to conduct comprehensive program reviews in 2011 and 2014. This potential shift in production intensity of baseline crude oil will be evaluated during these and subsequent program reviews and addressed via regulatory change if deemed necessary.

The carbon intensity of crude oil sources which are not part of the 2006 California baseline crude mix will be evaluated as they enter the California market. Treatment of these crude sources is specified in Section 95486(b)(2)(A) of the LCFS regulation. We

believe that this approach is appropriate as it helps to avoid shuffling of crude oil sources currently used in California refineries while also appropriately evaluating emissions from new sources of crude oil as they enter the California marketplace.

C-258. Comment: We also support CARB in ensuring that high carbon fuels, including those derived from Canadian and U.S. tar sands, oil shale, and liquid coal, are addressed in pathways that distinguish them from lower carbon petroleum fuels, thus protecting against the use of carbon intensive fuels while incentivizing cleaner fuels. (FOTE2)

Response: This supports the Board approved LCFS.

C-259. Comment: Adoption of the Low Carbon Fuel Standard will protect California from the dirtiest fuels. Production of high-carbon intensity fuels, including those derived from Canadian and U.S. tar sands, oil shale, and liquid coal, will emit as much as three to six times GHG emissions as conventional oil, threatening to undermine California's many efforts to reduce transportation emissions. The development of these ever-dirtier fossil-fuel sources to produce transportation fuels has enormous consequences not only for our climate, but the air we breathe, the water we drink, and our wildlands and wildlife in North America. (SIERRACLUB)

Response: This supports the Board approved LCFS.

C-260. Comment: Our previous comments showed, among other things, that corn ethanol fuel replacement will not solve and could worsen GHG and ground-level pollution (May, 2008), and that refining higher-sulfur crude is increasing GHG emissions from steam reforming to feed hydroprocessing by California refiners. (Karras et al., 2008) The attached research paper, Refinery GHG Emissions from Dirty Crude, provides new evidence that both problems are more extensive and interconnected than previously known—and that the PLCFS, as proposed, will not address these problems.

ARB should amend the PLCFS to:

- Add oil input quality caps for each refinery (an oil input quality cap is a set of limits applied at the point where oil is first introduced to processing after any blending that prevent increased gravity, sulfur, nitrogen, vanadium, nickel, vacuum gas oil yield, residua yield, mercury, selenium or total acid relative to the refinery's current oil input).
- Ban corn ethanol as a fuel
- Remove pollution trading as a compliance option

ARB should not adopt the PLCFS without first, at a minimum, making each of these three amendments. The reasons for this are explained below.

1. Increased emissions from refining dirtier oil could increase the lifecycle GHG

emission intensity of the oil-energy system substantially.

California is the predominant oil refining center of the Western United States. Yet, although it acknowledges the potential that a switch to different oil sources for California refineries could increase emissions from oil extraction, the PLCFS does not estimate GHG emissions from refining dirtier oil.

The attached research links dirtier oil to its energy-consuming processing mechanism and to observed refinery energy intensity quantitatively, across the U.S. refining industry during 2003 through 2007. Increasing gravity (mass/barrel) and sulfur content (percent mass) of oils refined caused a large (+47 percent) increase in refinery energy and emissions intensity, and could cause a very large (+25 percent to +230 percent) further increase in emissions/barrel depending on the extent to which dirtier oil is refined. Even at the current California crude gravity, the emissions increase is large (~123-149 percent) if sulfur increases to easily foreseeable levels—such as those of Persian Gulf oils. This is consistent with previous evidence for hydroprocessing-related emissions caused by higher-sulfur oil in California refineries. (Karras et al., 2008)

Limiting the worsening quality of oil refined is critical to environmental health and justice.

2. The PLCFS does not measure or address emissions from refining dirtier oil.

At least three fundamental errors in the design of the PLCFS cause it to not measure or address changes in refinery emissions intensity caused by dirtier oil.

Extraction v. refining: The reliance on oil extraction intensity as a measurement of oil quality impacts on refining intensity is an error. Geology and oil viscosity greatly affect extraction. Different oil quality factors, such as distillation yield, which is related to gravity, and contamination by sulfur, nitrogen and metals affect refining. (See Attachment) The PLCFS does not measure or address increased refinery emissions caused by dirtier oil because it ignores the oil quality factors that cause this refining impact. Thus, the PLCFS estimates that emissions intensity for oil extraction decreased when the sulfur content and the emission intensity of refining increased for hydroprocessing this same oil in the same period. (SR at App. C12; Karras et al., 2008).

Products v. processing: The PLCFS estimates of emissions from refining gasoline, and separately, diesel, rely on product-specific refining efficiency factors which it adjusts for average California conditions. (SR at IV-5; Detailed CA-GREET CARBOB Pathway at 28, note 9.) But these product factors do not account for oil quality impacts on refining. These product efficiency factors are explicitly based on the average crude quality and a single hypothetical refinery configuration. (Wang et al., 2004/8) Thus, they are designed not to measure the changes in processing, energy, and emissions intensity from refining dirtier oil.

(Attachment) In fact, based on data for the five U.S. refining districts during 2003-7, these product efficiency factors predict slightly decreasing refinery energy intensity when real-world refinery energy intensity, process intensity and oil input gravity and sulfur increased. (Id.)

Average v. plant: Compounding the errors above, the PLCFS establishes its oil-based fuel pathway—its real “standard” for fuel emissions intensity—at the average for all California refineries and oil inputs together. (SR at IV-6) This, by definition, allows individual refineries to retool for cheaper, dirtier oils that the PLCFS extraction intensity measurement would not detect. It thereby allows increasing refinery emission intensity.

3. The PLCFS does not analyze or address interactions of dirtier oil infrastructure, corn ethanol dominance of the replacement fuel market, and pollution trading.

Oil energy is more deeply entrenched than the other major sources of GHG emissions. (See e.g., LCFS-13) This predominant oil-based infrastructure stunts non-combustion fuel replacement alternatives—which cannot be blended with gasoline or diesel, carried in their liquid-fuel distribution networks, or burned by internal combustion engine vehicles—by competing for money and land. That forces replacement fuels toward other liquid fuels. (See LCFS-1)

Huge, long-lived capital investments in different equipment are necessary to extract and refine the relatively more available, and cheaper, dirtier oils. (Attachment, refs. 2, 8, 11, 16, 20) Thus, a switch to dirtier oil will further deepen the entrenchment of oil, and extend it for the decades-long operability of the new equipment. Therefore, in addition to its direct emissions from extraction and refining, a switch to dirtier oil would further force fuel replacement toward liquid combustion fuels.

Moreover, if the worsening quality of refinery oil inputs is not stopped and this along with pollution trading force corn ethanol’s dominance as the replacement fuel for gasoline, we will almost certainly fail to achieve the total GHG emission reductions widely believed to be essential for climate stabilization.

Emissions/barrel dirtier oil and ethanol emissions/barrel oil replaced could combine to overwhelm all other feasible emission reductions. In every credible scenario that includes a switch to dirtier oil with corn ethanol as substitute fuel, climate protection appears to be foreclosed. Even in a very hopeful scenario—70 percent of oil replaced; ethanol is only 25 percent of the fuel replacing it; with ethanol emission/gallon lower than today, and only a 25 percent increase in fuel production intensity from dirtier oil—it is barely mathematically possible and is not practically possible to reach the IPCC emission reduction for 2050. (CBE1, CBE2, CBE3, CBE4)

Response: The Board considered and did not accept the proposed changes to the

regulation that were suggested in these comments.

First, the LCFS lifecycle assessment for gasoline and diesel applies average efficiencies to all refineries, irrespective of the quality of crude oil sources and the complexity of the refining process. These average production and refining efficiencies are based on the 2006 California baseline crude oil mix used in California refineries. Over time there is potential for emissions from crude production and refining to increase. The Board directed staff to conduct comprehensive LCFS program reviews in 2011 and 2014. The potential shift in average carbon intensity of baseline fuels will be evaluated during these and subsequent program reviews and addressed via regulatory change if necessary. Furthermore, the regulation of non-greenhouse gas emissions from refineries is governed by existing regulations which are enforced by local air pollution control districts. Therefore, adding oil quality caps to control greenhouse gas and other emissions from refineries is unnecessary.

Second, as noted in the response to Comment C-251, the LCFS does not prohibit the sale or use of fuels that comply with the regulation. What the LCFS does is it introduces into the marketplace the additional consideration of lifecycle greenhouse gas emissions. Fuels that are both economical to produce and also have low greenhouse gas emissions will compete well under the LCFS. Those fuels with large lifecycle greenhouse gas emissions may still be used, but any increase in emissions relative to the compliance standard must be compensated for by increased use of fuels with low lifecycle greenhouse gas emissions. In summary, the LCFS is designed not to dictate which fuels can or cannot be used but rather is designed to introduce the additional consideration of lifecycle greenhouse gas emissions into the decision making process.

Finally, the LCFS is structured properly to stimulate the production and use of alternative low-carbon fuels which will diversify the transportation fuel market away from fossil fuels. These alternative low-carbon fuels may include both crop-based and advanced biofuels, low-carbon electricity, hydrogen, and landfill or digester natural gas. Although the regulation does not restrict the use of any crude oil source, use of petroleum fuels with an assigned carbon intensity value greater than the average will necessitate the use of even greater amounts of low-carbon alternative fuels in order for regulated parties to meet the compliance standard. This in turn leads to even greater diversification away from fossil fuels. See also response to C-259.

C-261. Comment: Crude oil definitions in LCFS are also problematic. The LCFS crude oil definition allows high carbon crude oils to be treated like low carbon crude. The draft LCFS only separates crude oil into two categories -- conventional crude oil and non-conventional crude oil (such as heavy Canadian tar sands crude oil which takes much more refining and energy to turn into gasoline and diesel, as well as heavy impacts in Canada during production).

This definition fails to acknowledge that there are many high carbon crude oils not described by the non-conventional crude oil definition. These crudes would be considered conventional according to the LCFS definition, even though they

are just as high carbon and require as much energy to refine as Canada tar sands crude.

For example, Venezuelan crude is a heavy, sour crude oil used in the U.S. and comparable to Canadian tar sands crude in API gravity (a measure of how heavy the crude oil is). The heavier the crude oil, the higher the carbon intensity. Under the LCFS definition, oil refineries in the state of California can continue their destructive switches to heavier crude oil without accounting for the higher carbon inputs, as long as these are not labeled by name as oil sands, tar sands, oil shale, gas-to-liquid, or coal-to-liquid crudes. There is no quantitative definition in the LCFS for separating crudes by API gravity; LCFS only separates them by applying names that are not comprehensive for identifying heavy crude. These higher carbon crude oils are also more contaminated with sulfur and heavy metals.

The definitions for non-conventional crude oils also allow complex "rebuttable" assumptions about carbon content. For example, these definitions allow non-conventional crude to use conventional crude average carbon values if the non-conventional crude is calculated within 10 percent of conventional crude values. This adds one more layer of hedging on actual GHG impacts, which in combination with major inaccuracies present in carbon trading and inaccuracies in calculating ethanol inputs further undermines the chances of LCFS' effectiveness. (CBE3)

Response: This comment addresses items that apply to earlier draft versions of the regulation. The approved LCFS no longer uses the terms conventional, non-conventional, oil sands, tar sands, oil shale, gas-to-liquid, or coal-to-liquid to classify crude oil sources. The LCFS classifies crude oil sources as those which are "included in the 2006 California baseline crude mix" and those which are not included. All crude oil sources that are not "included in the 2006 California baseline crude mix" must be evaluated individually when used in the California fuel market. Those sources with a production and transport carbon intensity similar to the average calculated for the California baseline crude mix (less than or equal to a threshold of 15 gCO₂e/MJ) will be classified as "non-high carbon intensity crude oil" sources and fuels derived from these sources will also receive the average carbon intensity value shown in the Lookup Table. Those sources with a production and transport carbon intensity greater than 15 gCO₂e/MJ will be classified as "high carbon intensity crude oil" sources and fuels derived from these sources must use the carbon intensity for their specific pathway as determined by Method 2B. Producers of "high carbon intensity crude oil" may use control measures, such as carbon capture and sequestration or other methods, to reduce the carbon intensity for production and transport to 15 gCO₂/MJ or less and consequently receive the average carbon intensity value from the Lookup Table. This classification of crude oil sources helps to minimize the shuffling of crude oil sources currently part of the California baseline crude mix while preserving the market signal placed on carbon content of new crude oil sources entering the state. ARB believes that potential exists for increased use of "high carbon intensity crude oil" in California.

The LCFS must accurately account for this increase in crude oil carbon intensity if it is to successfully achieve the program's average carbon intensity reduction goals.

C-262. Comment: This analysis also shows the continuing increase in sulfur content within the refinery due to this heavier, dirtier crude switch. Consequently, there will be higher concentrations of hazardous hydrogen sulfide and other sulfurous gases within California refineries, increasing hazards to neighbors and workers. This trend of higher energy use and more contaminated processing needs to be evaluated under AB 32 as part of the public health analysis, as an issue of co-pollutants generated due to fossil fuel use at refineries, as well as under section Health & Safety Code § 38570.

This is a grave matter of Environmental Justice as sulfur content at refineries translates to emissions that have severe impacts on people with asthma and other breathing problems, and heavy metals which include carcinogens and neurotoxins.

(Recommendations for fixing the Low Carbon Fuel Standard)

Add a public health analysis on the switch to heavier, higher sulfur crude oil at oil refineries that is occurring throughout the state, and which is not being addressed. (CBE3)

Response: Emissions from refineries are subject to local air district regulations and to permit conditions limiting emissions. See responses to Comments C-62 and C-260.

Periodic Review

C-263. Comment: There will be changes in accepted methodology as we go forward and it is imperative that the Board create a very flexible regulation with frequent periodic reviews and economic protection for facilities that are in compliance with prevailing regulations when construction starts. Based upon the changes I have observed during the regulatory process an annual review is needed during the early years as both the Life Cycle Analysis (LCA) and ILUC calculation methodologies evolve and stabilize. Reviews in 2010, 2011, 2013, 2015, and 2018 are reasonable. Of course the reviews themselves can recommend the next review period. (A2O4NESTE2:104)

Response: Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. In addition, an expert workgroup is created to evaluate issues related to the life cycle analysis and will report to the Board by the end of 2010. These reviews will ensure that any needed changes are made to the regulation so that it provides the needed flexibility and economic protection for facilities that are in compliance.

C-264. Comment: CARB should adopt provisions establishing a process to

periodically review progress against the goals and to make adjustments as necessary. The timeline for commercialization of new technologies can be difficult to predict and ultimately, the commercial success of these new technologies also depends on consumer acceptance. CARB should recognize this and expand the proposed regulatory review provision to make clear that reviews will take place every three years. In addition, these regulations should detail the content and process for the reviews. (SHELL, WSPA1)

Response: Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. Section 95489 also specifies the details and the content as well as the process for the reviews. These reviews will ensure that any needed changes are made to the regulation so that it provides the needed flexibility for the commercialization of new technologies.

C-265. Comment: As section 95489 of the proposed regulation recognizes, it is critical that the regulations include a process to monitor progress and make adjustments in the future. (SHELL)

Response: Section 95489 of the regulation specifies periodical reviews and will ensure that any needed changes to the regulation will be able to be made in a timely and efficient manner.

C-266. Comment: The program reviews should occur every three years. Section 95489 should also provide more specifics on the content of the review. At present, it merely states that the scope and content of the review is within the discretion of the Executive Officer. To ensure an orderly evaluation of progress and provide the regulated community more certainty, the scope and content of the reviews should be specified in the regulations. The review process should evaluate technology advances, assess the supply and rate of commercialization of new fuels and vehicles, the program's impact on the state's fuel supplies, and should identify hurdles or barriers (i.e., permitting issues, research funds, etc.) and recommend appropriate remedies. It is important that the milestone reviews be done in a timely fashion and that the industry be given adequate time to adjust to any regulatory changes. The milestone review should be conducted by key agencies and stakeholders including, but not limited to ARB, CEC, fuel providers, and engine and vehicle manufacturers. (SHELL)

Response: Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. Section 95489 also specifies the content and the process for the reviews. These reviews will ensure that any needed changes are made to the regulation so that it provides the needed flexibility for the commercialization of new technologies. All other interested agencies and stakeholders will be invited to participate in the reviews.

C267. Comment: The methodology of accounting for indirect land use change effects is evolving rapidly. Flexibility and review is essential. (A2O4NESTE2)

Response: Resolution 09-31 directs the Executive Officer to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effect analysis and to return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address the issues identified. This review will provide the needed flexibility.

C-268. Comment: We believe that these principles should guide a review not only of biofuels but of all fuel sources. We also wish to emphasize that there should be significant capacity to produce biofuels that do not divert the productive capacity of land. Much of the Department of Energy's analysis of potential U.S. biomass focuses on wastes and agricultural residuals, a portion of which can probably be used for energy while preserving other environmental needs. Countries like Brazil may also be able to adopt strategies to avoid indirect land use change. A proper concern for land use does not preclude a meaningful role for biofuels. (Princeton)

Response: We agree. The methodology that was adopted takes a proper approach and allows all biofuels as well as other fuels to be evaluated according to their GHG potential. The analysis takes into account indirect land use and it is expected that biofuels produced from biomass from wastes will have lower GHG potential. In addition, Resolution 09-31 directs the Executive Officer to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effect analysis and to return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address the issues identified. This review will ensure that the capacity to produce biofuels that do not divert the productive capacity of land is thoroughly evaluated and that the possibilities of using waste and agricultural residuals are thoroughly evaluated.

C-269. Comment: Regular, mandatory program reviews will have a critical role in keeping the pace of implementation matched to the pace of technology development while ensuring that the expectations of the monitoring public are met. We strongly encourage ARB to incorporate specific requirements for regular program reviews to be conducted by the Board at least every three years in addition to the 2012 review currently included in the proposed regulation. (CHEVRON1)

Response: Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. Section 95489 also specifies the content and the process for the reviews. These reviews will ensure that any needed changes are made to the regulation so that it provides the needed flexibility for the commercialization of new technologies.

C-270. Comment: We would suggest a mandatory public review written into the regulation so that we can accommodate new science as it comes up. (NESTE1)

Response: A mandatory review is part of the regulation. Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. Section 95489 also specifies the content and the process for the reviews. These reviews will accommodate new science as it comes up.

C-271. Comment: In order to address the inherent uncertainty in any future projections of low carbon fuel availability and cost, especially those which anticipate the commercialization of new technologies, the LCFS must include regulatory provisions for a regular periodic program review every three years. This review should be reflected in the regulation itself, should be conducted in conjunction with CEC and other key agencies, should be a public process that involves fuel providers, consumers, engine and vehicle manufacturers, and other key stakeholders, and should include review of the programs progress toward its targets, and any necessary adjustments to the compliance schedule. (AB32IMPG1)

Response: Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. Section 95489 also specifies the content and the process for the reviews. These reviews will ensure that any needed changes are made to the regulation so that it provides the needed flexibility for the commercialization of new technologies. Also, it will ensure that uncertainties in future projections of low carbon fuel availability and cost can be evaluated. All other interested agencies and stakeholders will be invited to participate in the reviews.

C-272. Comment: The regulation should include an annual 12-month review period rather than three years. (NESTE2)

Response: Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. In addition, an expert workgroup will be formed and will evaluate a number of issues and report to the Board of the findings or any refinements to the regulation that are needed prior to January 1, 2011. These reviews will ensure that any needed changes are made to the regulation so that it provides the needed flexibility and economic protection for facilities that are in compliance. The Board concluded that these reviews would be sufficient to address any changes to the regulation that needed to be made.

C-273. Comment: Reviews that are too frequent will kill this program. Continuous regulatory debate means that second generation biofuel investments will be stifled. (NRDC4)

Response: We agree. Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. These reviews will ensure that any needed changes are made to the regulation so that it provides the needed flexibility and economic protection for facilities that are in compliance. The Board concluded that these reviews would be sufficient to address any changes to the regulation that needed to be made.

C-274. Comment: As an extension to the existing scheduled regulation reviews, more frequent and targeted feasibility reviews would allow the regulation to match the development of alternative fuels without the scarcity-based market volatility associated with infeasibility. (BP1)

Response: Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. These reviews will allow the regulation to match the development of alternative fuels as they become feasible, thus reducing market volatility. The Board concluded that these reviews would be sufficient to address any changes to the regulation that needed to be made. Also see response to comment 11.

C-275. Comment: The ARB should include a resolution at the hearing requiring detailed triennial reviews of the program to be incorporated in the regulation itself. (WSPA1)

Response: Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. The Board found that these reviews will ensure that any needed changes are made to the regulation so that it provides the needed flexibility.

C-276. Comment: There is a need for a clear commitment in the regulation for completion of this work by the end of this year, and for triennial Board program reviews that include a stakeholder advisory group and full public process. (WSPA1)

Response: Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. The Board found that these reviews will ensure that any needed changes are made to the regulation so that it provides the needed flexibility. All stakeholders will be invited to participate in the review process.

C-277. Comment: The program reviews need to also provide a full public process, and we recommend the establishment of an advisory group open to all stakeholders. We support inclusion in the process of, at a minimum, the CEC and other key agencies, fuel providers, consumers, engine and vehicle manufacturers, and other key stakeholders. In addition, WSPA supports a regulatory hearing before the Board rather than a review being conducted only by

the Executive Officer. (WSPA1)

Response: Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. The Board found that these reviews will ensure that any needed changes are made to the regulation so that it provides the needed flexibility. In addition, the board in the adopted resolution directed for the creation of an advisory group to monitor progress. All stakeholders will be invited to participate in the review process. Also, the results of the review will be presented to the Board at a public meeting, and all stakeholders will be given the opportunity to comment on the review.

C-278. Comment: IWLA requests that CARB publicly review the regulation every six months until 2020 to ensure that vehicles and equipment are not harmed by reformulated fuel. The regulation must be evaluated annually every six months to determine supply, price, and volatility. (IWLA)

Response: Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. The Board found that these reviews will ensure that any needed changes are made to the regulation so that it provides the needed flexibility. In addition, on the diesel side, the Board is in the process of conducting a test program that will evaluate emissions and vehicle performance of different biodiesel blends. On the gasoline side, there are data and long-term experience with gasoline-ethanol blends indicating that there are no issues with vehicle performance. If different fuels with different chemical compositions are introduced that warrant establishing new fuel specifications, a multimedia and a vehicle evaluation process will be initiated. Based on these considerations, the Board concluded that these reviews would be sufficient to ensure that vehicles and equipment would not be harmed by reformulated fuel.

C-279. Comment: The U.S. EPA announced a proposed mandatory greenhouse gas reporting rule on March 10, 2009. The ARB staff should consider modifying its proposed methods of March 5, 2009 to take advantage of the future emergence of new, objective GHG metrics, and de-emphasize inferential modeling. (PRX)

Response: The ARB approach is an objective approach and it uses similar metrics as the U.S. EPA approach. Although the scope of the U.S. EPA program and its requirements are different than the scope and the requirements of the LCFS, U.S. EPA uses similar economic models to the ARB in order to estimate the GHG impacts. The ARB has been monitoring U.S. EPA's efforts and is in constant communications with U.S. EPA. In addition, the established expert workgroup will compare ARB and U.S. EPA approaches and will recommend any changes, if necessary. Furthermore, program reviews required by section 95489 will help ensure that the rule includes the most recent scientific understanding of lifecycle emissions and indirect land use effects. The program reviews will include making any necessary updates to the GREET and GTAP models to ensure that these models represent real world greenhouse gas emissions.

C-280. Comment: We believe that it is important for you to provide for a review of program every three years through a public process that involves key stakeholders. (CMTA, SCAQMD1)

Response: The Board found that a program review every three years was not necessary. Section 95489 requires that the Executive Officer conduct two reviews of the implementation of the LCFS program. These reviews will be completed by January 1, 2012, and January 1, 2015. All interested stakeholders will be invited to participate in the public review process. The program reviews will include making any necessary updates to the GREET and GTAP models to ensure that these models represent real world greenhouse gas emissions.

C-281. Comment: The AQMD staff recommends that the EER values used in the LCFS be updated routinely as new data become available. (SCAQMD1)

Response: Resolution 09-31 authorizes the Executive Officer to hold hearings for the purpose of revising the EER values as new data becomes available.

C-282. Comment: The AQMD staff is concerned about the possible increase in light duty dieselization which may occur under certain conditions allowed under the regulation. Therefore, the ARB should track the impacts of light duty dieselization. (SCAQMD1)

Response: As part of the rule implementation and program reviews, the ARB staff will track implementation issues, the fleet composition, and overall environmental impacts.

C-283. Comment: In order to track the efficacy of the LCFS over time, it will be constructive for CARB to establish a baseline greenhouse gas emission value and to track the actual greenhouse gas emissions associated with on-road transportation fuels. AQMD staff recommends that the Board direct the staff to include greenhouse gas emissions tracking as part of the LCFS implementation process. (SCAQMD1)

Response: As part of the rule implementation the ARB staff will monitor compliance progress and will track emissions to ensure that the progress required by the rule is being made.

C-284. Comment: A key determinant of a successful LCFS regulation is the expected pace of development of cellulosic biofuels. The ARB staff assumption of a competitive cellulosic ethanol market by 2012 is very optimistic. Significant additional steps beyond the Energy Independence and Security Act of 2007 will be needed, including significant technological and scientific breakthroughs with respect to C5 sugar conversion to ethanol, enzymes for the production of renewable gasoline and diesel formulations, algae production efficiency, biomass collection and processing, among other challenges. (SCAQMD1)

Response: During the implementation of the rule, ARB staff will monitor the development of the low carbon fuel technologies that will be needed to achieve compliance. If it appears that progress towards compliance with the rule is being jeopardized due to insufficient progress of the needed technologies, the staff will assess the need to make modifications to the rule. The staff will also consider ways to include in the rule additional incentives to increase the development of low carbon fuel technologies.

C-285. Comment: The AQMD recommends that ARB undertake a technological readiness and cost review of the federal Energy Independence and Security Act (EISA) targets in the context of the LCFS requirements. (SCAQMD1)

Response: The ARB staff will monitor the development and costs of technologies that will be used both to meet the EISA requirements and the low carbon fuel standard requirements. California fuel producers will be required to comply with EISA as well as with LCFS requirements. As part of this monitoring and as part of the LCFS program review, the staff will work with the EPA staff and will monitor the implementation of the EISA requirements. But the ARB staff alone has no authority to alter the requirements of the EISA. The ARB also found that although compliance with EISA will assist in complying with LCFS, the feasibility of compliance with the LCFS was not dependent on the requirements of the EISA.

C-286. Comment: The AQMD recommends that the LCFS credit market be carefully tracked before allowing its expansion into the domain of AB 32 emissions offset trading, and that future LCFS credit trading should be prohibited with the broader AB 32 program until after at least the first five years of LCFS implementation. (SCAQMD1)

Response: The ARB staff will track the LCFS credit market to ensure that no market distortions occur, or that supply and demand imbalances occur. The Board found that allowing LCFS credits to be exported from the LCFS program to other AB 32 regulations was not likely to disrupt or distort the overall credit market, or would likely not jeopardize the emission reductions of the LCFS. In order to ensure that there is no loss in emission reductions from the LCFS, the Board found that it would not be appropriate to allow credits to be imported into the LCFS program. These policies will be reviewed as part of the overall program review.

C-287. Comment: The Board should direct the staff to study the possibility of future changes in carbon intensity numbers for any fuel, the implications of CARB's options in such cases, and to return to the Board by December 2009 with recommended modifications to the regulation, as appropriate. (EIN2)

Comment: Rationale for this resolution EIN was pleased to hear in the March 27th, 2009 workshop that CARB is planning on looking into how it will address the situation in which a fuel's carbon intensity value is changed. Given what we

have seen in the last year alone, the possibility of revised science for these numbers is very real, and we believe CARB should do everything it can to reduce that regulatory risk. (EIN2)

Response: The Board has directed the staff to convene an expert workgroup to evaluate issues associated with various elements contributing to the carbon intensity. The expert workgroup will prepare a report to the Board with appropriate recommendations by January 1, 2011. In addition, during the implementation of the regulation, and for the program reviews scheduled by 2012 and 2015, the staff will monitor and review any developments on the GREET model and the GTAP models. If these reviews identify that refinements in the models are needed they will be incorporated in the analysis and will be used to estimate the new carbon intensity values. The staff will then propose these changes for Board's consideration.

C-288. Comment: Regular mandatory program reviews are going to have a key role in this program to ensure that the pace of technology introduction remains matched up with the pace of implementation of the requirements. Chevron is very pleased to see that the proposed modifications strengthen the commitment to these reviews. As part of these reviews, there should be a rigorous assessment of the capabilities for reducing carbon intensity over the next several-year interval of the program that should be based on concrete plans and actual plants and a minimum of speculation. (CHEVRON2)

Response: The Board program reviews by 2012 and 2015 will be comprehensive and will address the progress in the production of fuels that have reduced carbon intensity values.

C-289. Comment: Similar to how the carbon intensity for gasoline changes each year, the EER for FCVs and EVs should also change each year, to reflect the changing baseline. The LCFS should re-evaluate the EER tables as new data becomes available. (HONDA)

Response: The Board, in Resolution 9-31, has delegated to the Executive Officer the authority, following a public hearing, to conduct rulemakings to amend EER values or add new EERs and directed him/her to notify the Board of the results. Furthermore, the Board directed the Executive Office to re-evaluate EERs for heavy-duty vehicles and LNG, if appropriate. Since it is expected that, in the future, additional or new vehicles will be certified with new technologies, the database currently used for the development of EER values will be enhanced, allowing us to further refine the EER values.

C-290. Comment: Taken together, these findings clearly argue the need for further review of ILUC methodology before drawing quantitative conclusions. To quote Sheehan: The number of factors affecting the carbon impacts of land use change for biofuels is significant. Many of them are outside the control of the biofuels industry. The model shows any number of scenarios in which the carbon debt of land use change for biofuels can be almost eliminated. For these reasons,

indirect land use change should be regulated in [a] flexible way that incentivizes sustainable land management practices, rather than in a way that a priori penalizes the biofuels industry. (BIO)

Response: In Resolution 09-31, the Board directed the Executive Officer to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. The Board further directed the staff to return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. Part of the expert workgroup activities is the evaluation of various factors that affect carbon intensity values, including approaches that can result in reductions of carbon intensity.

Moreover, the Board directed the staff to work with stakeholders to present a workplan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation. Among other things, the workplan is to address how the sustainability provisions can incentivize sustainable fuels. The Board's directive requires the workplan to contain a schedule for finalizing sustainability provisions by no later than December 2011, unless the Executive Officer determines that such actions are not feasible and not appropriate.

Further, the Board directed the staff to work with interested stakeholders to develop criteria and a list of specific biofuel feedstocks that are expected to have no or inherently negligible land use effects on carbon intensity. The Board further directed staff to propose amendments, if appropriate, to the regulation resulting from this analysis by December 2009.

C-291. Comment: BIO counsels the Board to not lock in ILUC methodology, but to continue serious scientific studies aimed at improving modeling, securing reliable data, and resolving uncertainties. Such studies would be most usefully undertaken in conjunction with EPA's analyses of ILUC, which will also afford opportunity to share information with European and other nations studying the same issue, perhaps under the auspices of the National Academy of Sciences. (BIO)

Response: As noted in the previous response, the Board has considered the need to look at new studies and data. Accordingly, the Board directed the Executive Officer to create an expert workgroup to further evaluate and refine the ILUC methodology, including the modeling approach. The U.S. EPA, European Union and academia are expected to be represented on the expert workgroup. Those government and academic representatives will provide input on the process and on the recommendations that the staff will prepare, based on input from the expert workgroup, for the Board's consideration.

C-292. Comment: 1. The Board should direct its staff to continue soliciting input from all stakeholders and from the scientific community on appropriate ILUC modeling and reliable data sources, without any fixed commitment to GTAP or the

parameters used in GTAP, for a period of up to 2 years. As the attached analysis by Sheehan suggests, ILUC science is rapidly evolving in response to policy demand. An additional review period of 18 to 24 months will yield a much stronger consensus on both methodology and appropriate data, and establish a strong scientific foundation on which to base regulation.

2. During this period, the Board should coordinate its review of ILUC modeling with EPA's process for developing sounder science to support its rulemaking on the GHG emissions associated with different alternative fuels. Coordination with European regulatory processes studying ILUC should also be pursued. Comprehensive review by the National Academy of Sciences may also be warranted.

3. Following the review period, the Board should again publish a staff report and proposed regulations and transmit the report for peer review. This next time, peer reviews should be completed and posted for public comment before the public comment period on the proposed regulations begins. (BIO)

Response: With regard to first part, the Board has already taken steps in line with this suggestion. In Resolution 09-31 the Board directed the Executive Officer to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. Pursuant to Resolution 09-31, the expert workgroup will be tasked by the Board with evaluating key factors that might impact the land use values for biofuels, including agricultural yield improvements, co-product credits, land emission factors, food price elasticity, and other relevant factors. The activities of the expert workgroup will be public and stakeholder participation will be solicited. The Board further directed the staff to return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. The staff will prepare a report with findings and recommendations based on input from the expert workgroup; this staff report will be made available for public input and comments.

With regard to the second part of the comment, again the Board has taken steps in line with this suggestion. As part of its direction to convene an expert workgroup, the Board also directed the Executive Officer to coordinate this effort with similar efforts by the U.S. EPA, European Union, and other agencies pursuing a low carbon fuel standard. See also response to Comment C-291. The Executive Officer has the discretion to request additional external reviews of the expert workgroup's report, findings, and recommendations, but at this time the Executive Officer has deemed it too early to determine if such an external review is necessary.

With regard to the third part, the Board's direction to the Executive Officer was to propose regulatory amendments or recommendations, if appropriate, on approaches to address issues identified from the expert workgroup's input. Therefore, the need for a peer review depends on whether the Executive Officer proposes regulatory amendments from that effort. If there is such a proposed rulemaking to amend the

LCFS regulation, a separate *Initial Statement of Reasons: Staff Report* will be prepared in support of the proposed rulemaking. To the extent there is a scientific basis or scientific portion of the proposed rulemaking, as described in its supporting *Initial Statement of Reasons: Staff Report*, that scientific basis or portion will be subject to a peer review pursuant to HSC section 57004. If the Executive Officer deems a peer review is required pursuant to HSC section 57004, it is anticipated that the peer review comments would be published for public review at the start of the formal 45-day comment period leading up to the Board hearing to consider the proposed rulemaking. This has been and continues to be ARB's standard practice for publishing peer reviews of the scientific basis or portion of a proposed rulemaking pursuant to HSC section 57004.

C-293. Comment: Recommendation #4: We would recommend that CARB staff follow the recommendations of UNICA in readjusting the GREET CA model to update it to the more realistic situation in production of sugar cane in the current production now centered in Sao Paulo and other southern states. We also suggest that CARB staff look at the potential for a significant expansion of sugar cane acreage in Northeast Brazil where the greatest growth in sugar cane new acreage is occurring. This analysis should consider the potential that bagasse will be used for both production of ethanol and 2nd generation biofuel with the remaining residues used for steam production in much more efficient boilers. (CO2STAR)

Response: The Board created the latest sugarcane ethanol pathways taking into account data provided for electricity generation and for agricultural practices as they already are implemented. New practices or expansions in sugarcane production in different areas can be accounted for in the development of new pathways following the requirements set in the regulation Methods 2A and 2B. The Board staff has also developed a draft guidance document that discusses in detail how fuel producers can apply to use Methods 2A and 2B for new or improved fuel pathways.

C-294. Comment: Recommendation #5: Integrated strategies involving co-production of food & fish in conjunction with oil seed trees & intercropping is very difficult to model within the current GREET CA model. The example above requires changing many assumptions now used in looking at "land use change", "indirect land use change" and other variables now in models based on an assumption that increased biodiesel or renewable diesel demand will lead to expansion of only traditional oil seed crops. We recommend that CARB and/or California Energy Commission staff work together to develop a specific guidance document for the oil seed industry that suggests best practices for co-planting of oil seed trees with food crops to optimize the production of both food and fuel and to minimize the life cycle carbon impacts of oil production. (CO2STAR)

Response: In Resolution 09-31, the Board directed the Executive Office to work with interested stakeholders to develop criteria and a list of specific biofuel feedstocks that are expected to have no or inherently negligible land use effects on carbon intensity. A

draft list has been prepared and is expected to be presented to the Board in December 2009. Furthermore, the Board directed the Executive Office to work with stakeholders and develop a screening process for accessing carbon intensity of new or modified pathways. Existing tools (GREET and GTAP) may need to be modified to be able to incorporate the necessary parameters and inputs to perform the necessary analysis for some new and innovative pathways. We have already had preliminary discussions to that effect with some biofuel producers. This work will be completed when the producers of fuels define the details of the new pathways. Methods 2A and 2B allow the incorporation of the carbon intensity results of these new pathways in the lookup table.

C-295. Comment: We urge the Board to send a clear signal to conventional biofuel producers that the current carbon intensity values for biofuels will likely be adjusted upward in the next review of the program. The following provides more detail on why the carbon intensity values for biofuels may be too low. CARB's analysis of the indirect emissions from biofuels is based upon sound science, transparent analysis, and a judicious process. However, the proposed carbon intensity for biofuels is overly conservative, and will likely need to be adjusted upward in the future. To send an accurate signal to investors, the Board should provide adequate warning that biofuel emissions could and likely will be higher in future rulemakings. (UCS3)

Response: As noted in response to Comment C-292, in Resolution 09-31 the Board directed the Executive Officer to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels in California. The process, timeline, and expectations governing the activities of the expert workgroup are discussed in more detail in response to Comment C-292 and in Resolution 09-31. It should be noted that, in addition to the expert workgroup, the two mandated program reviews by 2012 and 2015 under section 95489 will help ensure that the LCFS regulation continues to reflect the latest, most scientifically valid information well into the future.

C-296. Comment: Mandatory periodic reviews will help ensure that this essential element is maintained. Periodic reviews will make consumers, policy makers, and industry better informed about the feasibility and potential economic benefits or detriments of the program. (CONOCO)

Response: The 2012 and 2015 program reviews as specified in section 95489 will evaluate, among other things, the feasibility and economic impacts of the program.

C-297. Comment: Section 95489 Regulation Review: Periodic reviews of the regulation are essential. We strongly encourage CARB to include stakeholders and other agencies (such as the CEC) in the review process. Achieving the compliance goals of the LCFS will be very dependent on development and commercialization of new technologies. It is imperative that the Agency periodically assess the progress of these technologies and make adjustments in

compliance schedules and requirements as necessary based on the outcome of the review process. (CONOCO)

Response: Section 95489(b) requires the creation of an advisory panel with representatives for stakeholders and other state agencies that will participate in the review process. The scope of the review process in section 95489 (a)(4) identifies the evaluation of development and commercialization of new technologies as one of its elements.

C-298. Comment: It is critical that the regulations include a process to monitor progress and make adjustments in the future.

Shell supports the Program Review recommendation made in section 6.a. of the concept outline. However, we strongly believe that this review process should be expanded to include potential adjustments to the LCFS interim targets based on these reviews. The milestone reviews should evaluate technology advances, assess the supply and rate of commercialization of new fuels and vehicles, the program's impact on the state's fuel supplies, and should identify hurdles or barriers (i.e. permitting issues, research funds, etc) and recommend appropriate remedies. It is important that the milestone reviews be done in a timely fashion and that the industry be given adequate time to adjust to any regulatory changes. The milestone review should be conducted by key agencies and stakeholders including but not limited to ARB, CEC, fuel providers, and engine and vehicle manufacturers. (SHELL)

Response: We agree and the regulation was modified accordingly.

C-299. Comment: In addition to reviewing the feasibility of the standards now before they are promulgated, it is critical that the regulations include a process to monitor progress and make adjustments in the future. There is no indication in the draft rules that CARB intends to conduct such reviews and we urge CARB to include a specific provision setting out the process to provide additional certainty to the regulated community. The review process should evaluate technology advances, assess the supply and rate of commercialization of new fuels and vehicles, the program's impact on the state's fuel supplies, and should identify hurdles or barriers (i.e. permitting issues, research funds, etc) and recommend appropriate remedies. It is important that the milestone reviews be done in a timely fashion and that the industry be given adequate time to adjust to any regulatory changes. The milestone review should be conducted by key agencies and stakeholders including but not limited to ARB, CEC, fuel providers, and engine and vehicle manufacturers. (SHELL)

Response: We agree and the regulation was modified accordingly.

C-300. Comment: Section 95429. Regulation Review: The language offered at the January 30 workshop is woefully inadequate. WSPA feels very strongly that the

LCFS regulation should require a periodic review on the order of every three years, not just one review in 2012.

In addition, we request the reviews be public processes, not just performed by the Executive Officer or ARB staff with no public input or review.

Third, we request that the regulation contain language specifying the scope and content of the reviews so there is no ambiguity in what the review is meant to cover. The reviews should evaluate the program's progress against the targets and make adjustments as necessary. Any economic and environmental issues that have arisen should also be analyzed. Some of the aspects that should be addressed in the periodic reviews are:

- > Any technology advances,
- > An assessment of the supply and rate of commercialization of fuels and vehicles,
- > The program's impact on the state's fuel supplies,
- > The program's impact on state revenues and consumers, and,
- > An identification of hurdles or barriers (i.e. permitting issues, research funds, etc) and recommendations for appropriate remedies.

It is important the periodic reviews be done in a timely fashion and that the industry be given adequate time to adjust to any regulatory changes. The periodic reviews should be conducted by key agencies and stakeholders including but not limited to ARB, CEC, fuel providers, and engine and vehicle manufacturers. (WSPA1)

Response: Section 95489 specifies program reviews by the Executive Officer on the implementation of the LCFS program and requires the results of the reviews to be presented to the Board. The first and second program reviews are required to be presented to the Board by January 1, 2012 and January 1, 2015, respectively. Section 95489(a) enumerates a list of topics to be covered at a minimum in these reviews, which includes the elements identified by the commenter. In addition, section 95489(b) requires the Executive Officer to establish by July 1, 2010 an advisory panel that should include representatives of CEC, other governmental agencies, fuel providers, engine and vehicle manufacturers, and various other stakeholders. The advisory panel will participate in the two program reviews, and the Executive Officer is required to solicit comments and evaluations from the panel on staff's assessments of the areas and elements specified in section 95489(a), as well as on other topics relevant to the program reviews. Section 95489(c) specifies that the program reviews will be conducted in a public process involving at least two public workshops for each review prior to the resulting program-review reports being presented to the Board.

Credit Trading

C-301. Comment: There is concern with the seemingly contradictory language regarding how LCFS credits will be exported to other GHG trading programs.

Current cap and trade proposal contradicts itself in that the proposed LCFS regulation allows the export and sale of LCFS to be the broader AB 32 Cap and Trade Program but, at the same time, restricts the sale of LCFS credits to “regulated parties” under the LCFS regulation. The Statement of Reasons makes clear that “The proposed regulation allows for the exporting of credits to other GHG trading programs” (p. V-23). But Section 95485(c)(1)(B) states that “a third party entity that is not a regulated party or acting on behalf of a regulated party, may not purchase, sell, or trade LCFS credits.” “Regulated party” is defined as an entity subject to the LCFS regulation in 95481(a)(40). This is confusing and negates the very advantage to export carbon credits to the broader AB 32 market. It is unclear how an LCFS credit can be exported “to other GHG trading programs” if the only parties that can buy the credits must be a “regulated party” under the LCFS. The only logical conclusion is that an LCFS credit can only be exported to another GHG trading program if it is sold to a party that is both an LCFS regulated party and also participating in other GHG trading programs. If so, that means the LCFS credit trading program is limited essentially to fuel refiners that are also participating in GHG reduction programs outside the LCFS. That result would be tantamount to not allowing trading outside the LCFS, thus severely limiting the opportunity to trade outside the LCFS. We cannot believe that is the intent of the Board, and we hope this important matter will be clarified in the final rule.

Therefore, paragraphs (c)(1)(B) and (C) of §95425 need to be clarified in order to accomplish the stated intention of allowing LCFS to be traded by regulated parties under the larger AB 32 Cap and Trade program and to enable third parties that are not “regulated parties” to purchase, sell or trade LCFS carbon credits. If the intention is to only allow “export” by regulated parties to other regulated parties to support their compliance with non-LCFS GHG regulatory requirements, then this would unduly limit both the markets open to regulated parties to obtain value for LCFS credits. (CNGVC, CE2, CE4, SEMPRA, CFC)

Response: The originally proposed language in section 95485(c)(1)(B) was modified in the First Notice of Modified Text to permit the export of LCFS credits to a third-party entity that is not a regulated party, but only for purposes of compliance with other GHG reduction initiatives including, but not limited to, programs established pursuant to AB 32. This modification addresses the concern raised by the commenters. While the modification allows the export of LCFS credits in specified but limited circumstances, it should be noted that such exported credits would still be subject to the requirements of the GHG program to which they were exported (i.e., the credits cannot be used in another GHG reduction program until that program is established and provides for imports of LCFS credits).

C-302. Comment: ARB should maximize public disclosure of LCFS compliance. The ISOR states that “Output reporting tools will provide regulated parties with access to their data. Our goal is to provide public access to summary reports of LCFS data and related information without disclosing confidential business information

or trade secrets.” While the ISOR gave a brief overview of ARB’s option to manage transactions, it does not propose which role ARB will fill. According to the earlier August 2007 UC Berkeley Policy Analysis Report, “Buyer and seller typically do not communicate the price of the allowance or any other information about the transaction to the regulators.” The ARB would “tend to be record keepers only” while “LCFS credit transactions may be with third parties” like many “firms [who] have entered the allowance trading market and provide services of various types including bringing buyers and sellers together in developing derivative products.” The effect of this would be to transfer the day-to-day operation of the LCFS from the ARB, who would be the record keepers only, to the regulated entities and third-party private firms for hire who may not have any interest in pollution reduction at all. Because only the buyer, seller, and/or anonymous third-party would know the price and details of trades, and the ARB records may only reflect cryptic serial numbers and summary reports, the effect of such a system would be to shut-out the public. (CERA2)

Response: The LCFS regulation as adopted identifies the method for generating and calculating LCFS credits and deficits (section 95485) and the data that each regulated party must submit to ARB on a regular basis (section 95484(c).) Disclosure of the submittals to the public will be subject to the California Public Records Act (Government Code section 6250 et seq.) and ARB’s confidentiality regulations (set forth in title 17, CCR, sections 91000-91022).

The ARB’s role with regard to credit transactions remains subject to further discussion and development. As discussed in the Staff Report at V-35 through V-36, the ARB can play a voluntary service role that runs the gamut between a hands-off regulator, a transactions clearinghouse, and a trade facilitator; each type of service that ARB can provide comes with distinct advantages and disadvantages.

The above notwithstanding, it is important to note that the implementation of the LCFS regulation does not depend on which voluntary service role is ultimately chosen for ARB. This is because, as noted above, the regulation already contains sufficient and specific methods, criteria, and requirements that apply to the calculation, generation, and reporting of credits and deficits. We expect that, whatever voluntary service role ARB chooses to play, the vast majority of credit transactions will remain as private, “arms-length” transaction between regulated parties. While it may be desirable for ARB to play a voluntary service role to enhance credit trades, the ARB’s primary regulatory interest would be in receiving sufficient information to verify credits, credit transactions, the buyers and sellers of such credits, and the volumes of the credits traded. Requirements for ARB to receive all this information is already provided for in the regulation and can be obtained without ARB’s voluntary service role, if any, being defined at this time.

It should also be noted that credits cannot be generated until the start of 2011, since the 2010 requirements are for reporting only. As adopted, the regulation does not allow non-regulated parties to acquire or sell LCFS credits except as otherwise specified in

section 95485(b) and (c) (i.e., until other GHG programs are established that would allow the import of LCFS credits). See also the response to Comment C-301.

C-303. Comment: In addition, we oppose the UC Berkeley report's assumptions about confidential business information. "Importantly, the Energy Commission holds confidential the data reported by individual companies under the Petroleum Industry Information Reporting Act (PIIRA). The Energy Commission aggregates the data to ensure confidentiality of information about individual companies. This may be important for the LCFS because data to certify the carbon intensity of fuels may be considered proprietary and would require the sort of handling that the PIIRA program already provides." If the CEC can handle CBI with requisite confidentiality protections the ARB can as well. Not all fuel-providers, such as electricity, natural gas, and hydrogen, are presumably already registered and tracked in PIIRA, meant only for businesses that "ship, receive, store, process, and sell crude oil and petroleum products in California." Because the ARB will already be setting up recording accounts and will calculate and issue credits under a trading scheme, we would urge the ARB to take additional oversight over traded transactions to ensure compliance with AB 32 requirements. We oppose a credit trading system for numerous reasons. However, if one is established, the ARB must provide additional oversight over the credit trading transactions and third parties so that the agency will know when proposed trades will disproportionately impact historically overburdened communities. (CERA2)

Response: The treatment of confidential data submitted pursuant to the LCFS regulation and ARB's voluntary role in providing credit-trading enhancement services is discussed in response to Comment C-302. As noted in the Staff Report at ES-2 and ES-3, the trading of credits between regulated parties is central to the proper functioning of the LCFS regulation. And as discussed in response to Comment C-303, the trading of credits in the LCFS program is expected to occur without ARB's involvement (other than to receive specified records) because the credit trading is not dependent on the voluntary role ARB chooses, if any, to provide services to regulated parties that enhance their credit trading. The online LCFS reporting tool, currently nearing completion, will provide ARB with the tools to track credits generated or traded, the parties involved, and the volumes of credits traded on a regular basis, as provided in section 95484(c).

In Resolution 09-31, the Board determined that the approved regulation meets the criteria set forth in HSC section 38562 (part of the California Global Warming Solutions Act of 2006). Health and Safety Code section 38562(b)(2) requires that the Board, in adopting a regulation pursuant to this section, ensure that activities undertaken to comply with the regulation do not disproportionately impact low-income communities. Thus, the Board has already determined that credit trading conducted pursuant to the approved regulation would not disproportionately impact low-income communities. Nevertheless, in Resolution 09-31 the Board directed the Executive Officer to monitor the implementation of the LCFS program and propose amendments for the Board's consideration when warranted. Therefore, if the Executive Officer determines during

the LCFS' implementation that improvements are needed with regard to credit trading, the Executive Officer may propose amendments for a future rulemaking or recommend other measures to implement such improvements.

C-304. Comment: Pollution trading schemes have historically and strategically excluded the public, and even the very government agencies charged with the directive to regulate the pollution, from the decision-making process, effectively excluding the very communities that will be affected by industrial pollution.

In fact, the public faces numerous difficulties finding out what companies are trading to avoid compliance with pollution control standards... In this way, the democratic will, as represented in permit and regulatory requirements imposed after full public review and comment, can be reversed by a simple economic transaction.

Public accountability is vital when pollution trading programs create incentives for regulated entities to manipulate numbers and cheat so long as fraudulently-created credits are still opportunities to profit. The Los Angeles car-scrapping program was plagued by widespread under-reporting of *actual* emissions from industry and an over-reporting of *claimed* emissions reductions from cars, when pollution trading programs rely upon industry self-reporting of emission reductions. Similarly, the UC Berkeley Policy Report identifies self-reporting of annual fuel sales as the principle mechanism of enforcement under the LCFS, and identifies "fraud in their handling" as "possible" because "LCFS credits are likely to be valuable[.]" However, the UC Report's proposed solution, having the ARB serve as a record keeper only tracking serial numbers on accounts, does not address the over-arching concern for public accountability, when not even the ARB may know the details of the transactions. We oppose the UC Berkeley Policy Report's proposal to not communicate the price and transaction to the regulator. (CERA2)

Response: See response to Comments C-301 through C-303.

C-305. Comment: It is therefore our recommendation that Staff incorporate the following elements into the final regulations to insure an efficient and stable market for the motor fuels of today as well as advanced fuels and associated credits of the future.

- a. Address competing settlement periods by requiring more frequent submission of credits by parties obligated to comply with the regulations.
- b. Allow the generation of credits on a daily basis to support commercial settlement. (CFC)

Response: In Resolution 09-31, the Board determined that the regulation as approved, including its provisions for credit generation and trading, will achieve the maximum technologically feasible and cost-effective GHG emission reductions from transportation

fuel used in California and will encourage early compliance with the requirements. The regulation as approved provides for the generation of credits on a quarterly basis (see section 95485(b)) and the reconciling of the credit balance on an annual basis (see section 95484(b)). Moreover, the Board found that the GHG reductions resulting from the LCFS' implementation are expected to be real, permanent, quantifiable, verifiable, and enforceable by ARB, and the regulation complements and does not interfere with other air quality efforts. This finding is consistent with the Board's finding that the regulation meets the criteria in HSC section 38562 (see response to Comment C-303). Based on the above considerations, there is no compelling reason to modify the regulation as suggested by the commenter. See also response to Comments C-302 and C-303.

C-306. Comment: It is recommended that staff include the following elements into the final regulations:

- a. Require all parties to participate on a central registry.
- b. Implement safeguards and take aggressive action against acts of fraud
- c. Partner with the private sector to certify credits and the fuel path. (CFC)

Response: All regulated parties are required to comply with the annual compliance schedule and credit balance requirements set forth in section 95484(b). ARB staff is developing the Credit Tracking System (CTS) as an online application that will enable regulated parties to track their LCFS credit balance and credit trades. The CTS will securely maintain and report credit/deficit status as well as a credit trading history for each regulated party. The user interface will include detailed annotations and online help to facilitate reporting. The CTS will handle all fuels calculations required to establish the "Credit" or "Deficit" value for each regulated party. This will facilitate the LCFS credit balance determination and help detect instances of fraud. Audits of records required on a per-request basis will also help detect and deter instances of fraud (see 95484(d)). The information submitted to ARB through the CTS and other mechanisms will be secured and available only to each regulated party that submitted the data, ARB enforcement and program staff, or as otherwise called for under the California Public Records Act and other State laws.

See also response to Comments C-302, C-303, and C-305.

C-307. Comment: ConocoPhillips recommends allowance of early credit generation on 2010 should the rule be adopted for 2010 implementation. As proposed, full reporting is required in 2010; therefore, sufficient information would be available to determine credit generation. ConocoPhillips also recommends removing the word "quarterly" (credits should be allowed to be generated on annual basis as well). (CONOCO)

Response: Only reporting requirements apply for 2010. Since there is no applicable standard for 2010, it is not appropriate to allow the generation of credits.

C-308. Comment: Early credit generation. In earlier drafts, ARB staff indicated regulated and exempted parties cannot generate LCFS credits from voluntary actions prior to 2010. It is assumed that encouraging early and real GHG emission reductions is an admirable goal and we hope ARB would support such actions if a viable and enforceable means could be developed to regulate it. Now that the compliance schedule has been altered to contain just reporting in 2010 and intensity reductions starting in 2011, we believe there is increased opportunity for regulated parties to generate early credits for early action. For illustrative purposes, some possible actions that a regulated or exempted party could take to create early credits might include:

- Contract for the delivery of sugar-cane ethanol instead of corn-based ethanol.
- Blending of biodiesel or renewable diesel in CARB ULSD; and,
- Increasing the amount of ethanol in gasoline where the ethanol has a lower CI than what had been used. WSPA would like an opportunity to discuss possible early credit compliance processes with ARB. (WSPA1)

Response: The issue of early credits generation was discussed in response to Comment C-306. In summary, the regulation provides for no credits to be issued in 2010 because the regulation requires only reporting for that year. Because no credits are being provided for 2010, it would make little sense to provide credits for actions taken in 2009, before the LCFS standards go into effect, or even earlier.

C-309. Comment: Capping of Early Credits. WSPA believes it is very important that ARB not limit the amount of credits any one party can generate and bank for future sales or use. Likewise, there should be no discounting in the value of early credits. (WSPA1)

Response: The regulation, as approved, does not impose a cap on credits after January 1, 2011, neither does the regulation discount the value of credits. There were concerns raised regarding the possibility of generating substantial excess credits by some alternative fuels in the early years of the LCFS program, which in turn might stifle the development of low carbon-intensity fuels in the future. This concern was considered and determined to be unlikely to occur. Therefore, the regulation does not place a cap on the amount of credits a single regulated party can generate or bank. Beginning in 2011, regulated parties could start generating credits that can be banked indefinitely and used for compliance purposes, sold to other regulated parties, exported to other GHG reduction programs or purchased and retired by regulated parties.

The one constraint on the use of credits generated is set forth in section 95484(b)(4) (Deficit Reconciliation). This provision requires a regulated party with a deficit at the end of a compliance period to eliminate the deficit by retirement of banked credits, either fully or to the extent that banked credits are available, by purchase of sufficient credits, or by a combination of these methods. This provision was established in the originally proposed regulatory text and was not modified subsequently by the Board.

It should be emphasized that the above discussion applies to credits generated after January 1, 2011, not to early credits (i.e., credits for voluntary actions taken in 2010 or earlier) as suggested by the commenter. The issue of early credits is discussed in response to Comment C-308.

C-310. Comment: One of our concerns is around the ultra low carbon fuels, and whether the LCFS will provide a sufficient incentive for the development of ultra low carbon fuels, and in particular the non-liquid ones. We've heard a lot about biofuels today and those can be blended into our existing fuel supplies. But the hydrogen and the electricity and the natural gas that we're all hoping to see come on line to be able to meet our 2050 goals. They need a strong incentive too. And currently, the way it's structured, that incentive depends very heavily on somebody willing to buy the credits that we will be issuing these fuel producers. So our concern is that the LCFS, the way it's structured right now, does not really provide a guarantee that sellers of those credits will find buyers and that this will really translate into a revenue stream that they can bank on. (EIN3, WSPA1)

Response: The approved regulation, with its back-loaded compliance schedule, is sufficiently stringent to incentivize the purchase of credits from ultralow-carbon fuels, particularly non-liquid fuels. Ultralow-carbon fuels (i.e., those opt-in fuels under section 95480.1(b)) can provide substantial amounts of credits that will be valuable to regulated parties of higher carbon-intensity petroleum fuels. The need for such credits will be especially strong in the latter phase of the program, but there will also be the incentive for regulated parties to buy such credits in the early years and bank them for future use. See response to comment C-310.

A requirement that guarantees the purchase of credits, even credits from ultralow-carbon fuels, is contrary to the free market principles on which the LCFS regulation is based. This was discussed in more detail in response to Comment D-2. Although the LCFS relies on free market principles, the Board is cognizant of the need to encourage the purchase of very low and ultralow carbon-intensity fuels. After all, the goals of the LCFS program include the need to diversify the State's transportation fuel pool, stimulate the development of substantially lower-carbon transportation fuels, achieve long term reductions in GHG emissions from transportation fuels, and reduce the State's dependence on petroleum.

In light of these goals, the Board in Resolution 09-31 directed the Executive Officer to, among other things:

- a. work with interested stakeholders to develop criteria and a list of specific biofuel feedstocks that are expected to have no or inherently negligible land use effects on carbon intensity and to propose amendments, if appropriate, to the regulation resulting from this analysis by December 2009;
- b. conduct and complete rulemakings to add to or amend the list of opt-in, low-carbon fuels specified in section 95480.1(b); and

- c. monitor the implementation of the regulation and to propose amendments to the regulation for the Board's consideration when warranted.

Further, section 95489(a) requires the Executive Officer to conduct two LCFS program reviews by 2012 and 2015, the minimum scope of which is specified. Among the enumerated aspects to be reviewed, section 95489(a)(5) specifically requires the Executive Officer to consider the availability and use of ultralow carbon fuels to achieve the LCFS standards and the advisability of establishing additional mechanisms to incentivize higher volumes of these fuels to be used.

Based on the above, it is anticipated that the LCFS program will provide substantial and sufficient incentives to encourage the growth of ultralow-carbon fuels. But if such growth needs further enhancement, the Executive Officer is directed under both Resolution 09-31 and section 95489 to identify ways to increase the availability and use of ultralow-carbon fuels to achieve the LCFS standards.

C-311. Comment: ARB will hear a little bit about the need to ensure credit transparency, as staff develops the credit tracking and framework for the rest of the regulation.

If credits are not available or cost prohibitive, what remedies exist on the part of fuel providers to come into compliance with the proposed regulation? Simply asserting that credits will be available does not mean they will be affordable. It is a concern that credits may be hoarded by certain producers to artificially drive up the cost to other producers of transportation fuels.

It is requested that CARB clarify in the LCFS regulation that all reported compliance information, including credit status and credit banking, is a public document and will not be considered trade secret. In Section 95485(d), the proposed regulation states that "LCFS credits shall not constitute instruments, securities, or any other form of property." The regulation is requested to be modified to add the following statement: "Further, LCFS credits are a record of compliance and will not be considered to be a trade secret of a regulated entity."

CARB should not require regulated parties to publicly divulge detailed information regarding how many credits they have. Making such information public will likely have significant adverse impacts on parties seeking to buy and sell credits. For example, if a regulated party is substantially short credits and this were made public, this could result in the regulated party having to pay a much higher price for credits driving up the cost of compliance, and potentially the price of fuel to consumers. (ENVCLN1, CSC, FOTE2, SHELL)

Response: The treatment of confidential data submitted pursuant to the LCFS regulation is discussed in response to Comment C-302. Because existing State law and ARB regulations already provide specific requirements for the treatment of trade

secrets and confidential information, there is no need to specifically identify LCFS credits as a record of compliance in accordance with the commenters' suggestion. A scenario essentially the same as the one identified by the commenters, in which a regulated party may be at a bargaining disadvantage when it is substantially short of credits, is addressed in response to Comment D-2. These considerations, as well as the requirements of the Public Records Act (Government Code section 6250 et seq.) and ARB's confidentiality regulations (title 17, CCR, sections 91000-91022), would need to be considered before ARB publishes credits-related information.

C-312. Comment: ConocoPhillips opposes this section (C)(2)(A) concerning credit acquisition, banking, borrowing and trading. The one-way limit on credit trading (LCFS credit may be exported for compliance with other greenhouse gas reduction initiatives, however, credits generated from outside the LCFS program cannot be used in the LCFS) constrains optimization and limits the cost effectiveness of the program. This isolation concept is also counter to AB 32 which requires "...the state board to adopt rules and regulations... to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions..." The Bill also authorizes "... the state board to adopt market-based compliance mechanisms..." Allowing exchange of credits between programs will result in reductions where they are the most cost-effective and will accrue benefits to California citizens. Given the current economic situation and constraints, it is an extremely important factor to minimize the economic impact to businesses and consumers as the result of these new program adoptions. (CONOCO)

Response: The contribution of transportation fuels to total GHG emissions is sufficiently important to require actual improvements in the carbon intensity of transportation fuels. Because of this, the LCFS regulation prohibits the importing of credits from outside the LCFS program, borrowing from anticipated credits, and generating credits from exempt fuels (e.g., aviation, certain train and marine vessel fuels). This is to ensure that the regulation achieves real improvements in the LCFS fuel pool. For the prohibition on borrowing credits, there was the additional consideration that this concept is relatively untested and would likely have been problematic in California. And although the approved regulation prohibits credits from exempt fuels (under section 95480.1(a) or (d)), the staff will continue to evaluate the feasibility and effectiveness of allowing credits generated from the marine and aviation transportation sectors. These prohibitions and considerations were discussed in the Staff Report on pages V-23 and V-24.

C-313. Comment: In keeping with the view of ensuring that the LCFS is effective in reducing global warming pollution, there are serious concerns with provisions allowing for credits to be exported from the LCFS program to a larger market under the AB 32 cap. CARB is being discouraged from allowing the LCFS to export credits to a larger AB 32 market for compliance purposes since this could undermine the emissions reductions being sought under the cap, and create additional uncertainty about what the appropriate value of carbon emissions

should be under AB 32, should a carbon market ever get up and running.
(CVAQ, EDF2)

Response: As noted in response to Comment C-301, the approved LCFS regulation allows the export of credits for the limited purpose of compliance with other GHG reduction initiatives (section 95485(c)(1)(C)), including programs established pursuant to AB 32. However, an exported LCFS credit would remain subject to the import requirements and restrictions in the GHG reduction initiative to which the LCFS credit was exported. It then follows that, if the importing of LCFS credits into a program like the AB 32 cap-and-trade program would undermine that program's GHG emissions cap, the cap-and-trade program would presumably be designed to avoid such a result.

C-314. Comment: A "LCFS market" for credit trading is authorized in the LCFS regulation. However, there are no oversight mechanisms specifically designed to address the unique issues surrounding the trading of GHG emission credits for carbon intensity credits. No such market exists in the world at present. Given the complex scope of the well-to-wheels calculations, which will determine the magnitude and valuation of these credits, adequate oversight of carbon intensity credit market alone will present major resource issues to CARB. AQMD staff recommends that the LCFS carbon intensity market be carefully tracked before allowing its expansion into the domain of AB 32 emission offset trading, and that future LCFS carbon intensity credit trading should be prohibited with the broader AB 32 program until after at least the first five years of LCFS implementation.
(SCAQMD1)

Response: As noted in response to Comments C-301 and C-313, the actual role of LCFS credits in other AB 32 trading programs will be dictated by the requirements of those other programs.

C-315. Comment: CARB should not limit the ability of regulated parties to bank credits. CARB proposes to limit participation in the low carbon fuel credit trading program to obligated parties. We agree with this approach. The low carbon fuel standard will be very challenging for obligated parties. Consequently, all available credits should be available to obligated parties for the purpose of compliance. Due to the likelihood that credits will be in limited supply, non-obligated parties should not have the ability to remove credits from the market. If they did so, it could either reduce the supply of fuels available to consumers or unnecessarily increase costs. Longer-term, as the regulatory program evolves, and advanced fuel technologies become commercialized and more available, in its periodic program reviews, CARB should continue to evaluate whether non-obligated parties should be allowed to participate in the credit trading program.
(SHELL)

Response: The regulation approved by the Board contains no restrictions on the banking of credits. And as noted in response to Comments C-301 and C-313, the approved regulation generally prohibits the export of LCFS credits except for the limited

purpose of compliance with other GHG reductions initiatives. Under those limited circumstances, a regulated party can export an LCFS credit to another regulated party or to a non-regulated party for the limited purpose of compliance with another GHG reduction initiative. Although exporting LCFS is allowed under those limited circumstances, such exports are not expected to significantly reduce the overall amount of LCFS credits available to regulated parties within the LCFS program. In any case, a re-evaluation of this provision can fall within the scope of both the ongoing monitoring of the LCFS program, which the Executive Officer was directed to do in Resolution 09-31, and the two program reviews the Executive Officer is required to do under section 95489.

C-316. Comment: As it is currently written, this Section 95425(c)(2), p33 limits the purchase, sale, and trading of LCFS credits to regulated parties or a 3rd party acting on behalf of a regulated entity. We discussed this issue with CARB staff on January 29th and understand there are a number of major corporate opponents that do not want to see carbon brokers involved in the LCFS program.

While we appreciate the opinion of these opponents, WM still believes that this language could stifle the development of a proper trading market for LCFS credits. In a large-scale market-based program like the LCFS, WM would like to see third party carbon brokers able to “make a market” for these credits. This type of market making activity tends to increase the liquidity of these credits, stimulate firms to generate these types of credits, and improve price transparency. These activities also tend to make it easier for more companies to meet their compliance obligations under the new LCFS. Furthermore, WM is concerned that some of the larger entities regulated under the LCFS could “band together” to manipulate pricing in the LCFS credit market.

WM respectfully suggests that this section be removed in its entirety. (WM2)

Response: We believe the approach taken will help keep LCFS credit transactions simple in the early years of the program and contribute to an effectively working market (Staff Report at V-23). See also response to Comments C-301 and C-313.

C-317. Comment: ARB needs to explain in the LCFS regulation how it anticipates handling the LCFS program and the Transportation Fuels under a Cap & Trade program that has been imported into the Scoping Plan from the WCI. Does the state expect to have separate LCFS and cap and trade components for transportation fuels? How are both these programs going to relate to the federal EISA or RFS2 requirements? How are the California GHG/LCFS programs going to relate to the RFS2 and to any future federal climate change programs including a LCFS, when they are adopted? (WSPA1)

Response: Because the AB 32 cap-and-trade regulation is in its early stages of development, it is impossible to determine at this time exactly how the LCFS and

cap-and-trade programs will interact. Under the AB 32 Scoping Plan (Scoping Plan), the Board plans to incorporate transportation fuels into the AB 32 cap-and-trade program in 2015. This may require provisions to be incorporated into the LCFS regulation to facilitate the future integration of the LCFS with the AB 32 cap-and-trade program.

In Resolution 09-31, the Board found that the LCFS regulation is complementary to the federal RFS2 program. To ensure that this compatibility is maintained in the future, the Board directed the Executive Officer to coordinate efforts with the U.S. EPA to the extent feasible. To this end, staff will monitor federal actions and take steps, if necessary, to maintain the LCFS' compatibility with such federal efforts.

C318. Comment: One of the goals of the AB 32 and LCFS programs is to reduce petroleum use significantly by 2020. Estimates in the document are the programs will result in a 25 percent gasoline reduction and more than 15 percent diesel reduction. If true -- will the associated refinery GHG reductions from cutting back production be credited to the cap/trade program? (WSPA1)

Response: This comment falls outside the scope of the Notice and therefore requires no further response. With that said, the commenter's question has been forwarded to the program staff involved with the AB 32 cap-and-trade program, which is currently under development.

C-319. Comment: In addition, to the extent that an obligated party goes beyond what is required to comply with AB 32, we believe that this should result in the generation of credits that can be banked or traded under AB 32. (SHELL)

Response: Because the commenter is suggesting a provision be included in a program that is being developed outside of the LCFS regulation, this comment falls outside the scope of the Notice and requires no further response. The generation and disposition of AB 32 credits presumably will be covered under the cap-and-trade program.

C-320. Comment: Sempra Energy requests that a provision be included in the regulation to allow the Executive Officer to add additional fuels to the [fuel pathway] list as appropriate without the need for adoption by the Board of formal amendment to the regulation. (SEMPRA1)

Response: As discussed in Attachment B to Resolution 09-31 and in the First 15-Day Change Notice, staff became concerned that under the original proposal, the Executive Officer's action of certifying carbon intensity values could have the effect of establishing an important element of the regulation without following the rule-adoption process or applying robust criteria in the regulation that significantly narrow the Executive Officer's discretion in certifying carbon intensity values. This could have resulted in disapproval of the mechanism by the Office of Administrative Law. Concerns were also raised that, as initially proposed, the certification process might not be sufficiently transparent.

Therefore, the Board concluded that, at this time, new rulemakings are legally required for the establishment of new pathways.

Pursuant to sections 39515, 39516, 39600, and 39601 of the Health and Safety Code, the Board delegated to the Executive Officer broad authority to conduct and complete rulemakings to add new or customized fuel pathways and carbon intensity values to the Carbon Intensity Lookup Table in section 95486 of the regulation. The sole exception to the Board's delegation is for rulemakings involving modifications to the carbon intensity values based on land use or other indirect effects that are specified in the Carbon Intensity Lookup Table in section 95486 as adopted in this rulemaking. Under that exception, the Board reserved for itself the power to conduct rulemakings to modify such carbon intensity values.

Further, the Board has directed the Executive Officer to work with interested stakeholders to prepare guidelines for the addition of new pathways to the Lookup Table. The process for development of a guideline document is underway. A first draft was released for stakeholder input on August 4, 2009. The final draft of the guidelines is due to the Board by December 2009. These guidelines will assist the regulated parties in determining the data, documentation, and other information needed to support the expeditious development of carbon intensity values for new and modified fuel pathways. A detailed description of the application process will also be provided in this document.

Other Regulatory Comments

C-321. Comment: Need to specify fuels for Table 4 – it appears that under ARB's definition of blend stock, a refiner would be obligated to report the blend components in CARBOB. We have suggested the LCFS be consistent as possible with current CBG reporting requirements. (WSPA1)

Comment: Since the carbon intensity of CARBOB is based on an industry average we question the need for reporting such requirements. We therefore don't believe this is necessary and the definition of blend stock, for Table 4 only, should be adjusted to delete this requirement. ARB should specify that for Table 4, the blend stocks that make up CARBOB, CARB and CARB diesel need not be reported. (WSPA1)

Comment: ConocoPhillips seeks clarification regarding terms and requirements in Table 4 (Summary Checklist for Reporting). The terms "blendstock", "blendstock feedstock" and "feedstock origin" are not applicable regarding the production of CARBOB and CARB diesel. It is also not clear why in previous versions of the table, certain fields were "optional" and now they are "required". Please explain. ConocoPhillips believes that every element of "required" reporting must have a direct regulatory compliance purpose (as opposed to "information gathering"). (CONOCO)

Response: It appears the commenters are referring to language in earlier versions of the draft regulation that no longer apply. Section 95484(c)(3)(A)3 was changed under the 2nd Notice of Modified Text to remove the requirement for detailed gasoline and diesel component blendstock reporting. The modified quarterly reporting requirements specific to gasoline and diesel fuel now allow the regulated party to report the total volume of each blendstock aggregated for each distinct carbon intensity value (e.g., X gallons of blendstock with A gCO₂e/MJ, Y gallons of blendstock with B gCO₂e/MJ, etc.). CARBOB is a blendstock for gasoline and has a carbon intensity value that depends on what blendstocks are added to the CARBOB. The composition or “blendstocks” comprising CARBOB and CARB diesel are not reported as these are included in derivation of the corresponding carbon intensity.

There is a requirement for detailed reporting of CARBOB to indicate the percent of CARBOB derived from high-intensity carbon crude oil. This will need to be reported to ARB as a percentage of the CARBOB mix. If a regulated party is subject to section 95486(b)(2)(A)2. for fuel or blendstock derived from high carbon-intensity crude oil (HCICO), the regulated party must report the specified information set forth in section 95486(b)(2)(A)2.i. and ii. per each compliance period.

C-322. Comment: We ask that you acknowledge the past lessons when CARB used a 5-year lead time and a commercialized product. Under early action for AB 32 implementation, CARB is planning to adopt an LCFS within an 18-month lead time even though Europeans evaluated and dismissed low carbon fuel based on the same data CARB is currently accepting. Less science, no commercialization pathway, no economic analysis, and no successful implementation in another country; by taking this path, CARB will repeat its practice of ignoring science and pushing a bizarre anti-California based-business agenda. (IWLAGRP)

Response: ARB has not established a precedent for a five-year lead time. Lead times are determined on a case-by-case basis. Staff review and analyze the science and information available. Staff also holds several workshops and works very closely with stakeholders in order to determine appropriate lead times. The Board has determined that there was sufficient science and data to proceed with the LCFS. Please see ISOR VIII Pages VIII-1 to VIII-49 for the economic analysis on the LCFS. The Board approved a market driven commercialization pathway. Please see ISOR VI., Pages VI-1 to VI-22 for compliance scenarios.

C-323. Comment: The precedence set by allowing flawed and exclusionary rules to set standards for not only California but the nation, would be a staggering detriment to our country and would slow the development of technologies that can reduce our reliance on petroleum and other fossil fuels. In the end, the reductions you seek will likely not be reached because the reasoning is based upon a single-minded approach. The proposed LCFS developed by CARB does not consider the impact of other products and services that place significant carbon burdens – many exceeding the footprint of renewable fuels. (SDCUC)

Response: A complete lifecycle analysis was done on existing fuels and biofuels, as well as, possible future fuels and biofuels. The lifecycle analysis took into account products and services that go into making the fuel as well as the emissions expected from the fuels. Please see ISOR IV Pages IV-1 to IV-51 for the lifecycle analysis on the LCFS.

C-324. Comment: BP has encouraged CARB to consider allowing actions taken in the 2010 reporting period be allowed to obtain LCFS credits that can be used for their compliance once the LCFS is implemented in 2011. We believe that allowing early reduction credits for such actions will promote earlier implementation of activities reducing GHGs - helping to ensure a successful LCFS program. (BP1)

Response: The Board approved 2010 as a reporting year only. Accordingly, there is no GHG reduction requirement and no credit generation in 2010.

C-325. Comment: Since AB 118 funds are not to be spent to help parties comply with existing laws, regulations, etc, how will the resulting surplus GHG emissions be accounted for under the Scoping Plan and the LCFS? (WSPA1)

Response: AB 118 (Nunez, Stats. 2007, ch. 750) is a State funding program that authorizes the California Energy Commission (CEC) to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the State's climate change policies. Eligible projects for AB 118 funding generally do not include those that are required pursuant to State or federal law or district rules or regulations. However, the CEC has published a guidance document, "Clarification on Funding Restrictions: Regulatory Language," that provides a discussion of the circumstances under which AB 118 funds may be provided to LCFS regulation parties. See http://www.energy.ca.gov/ab118/documents/2008-09-26_FUNDING_RESTRICTIONS.PDF. An additional discussion of the AB 118 program is provided in the Staff Report at V-23.

The expenditure of AB 118 monies has no effect on the LCFS credit balancing and accounting. This is because, under the LCFS regulation, what matters is whether regulated parties meet their credit balance requirements at the end of each compliance period, not how the regulated parties paid for the reductions in carbon intensity. Whether LCFS regulated parties qualify for funding under AB 118 is dependent on the requirements and criteria of that CEC program rather than those of the LCFS regulation. Therefore, if the AB 118 program provides funds to LCFS regulated parties, and the regulated parties use such funds to reduce their fuels' carbon intensity in accordance with the LCFS requirements, the accounting for any resulting surplus reductions is entirely up to the AB 118 program. As far as the LCFS program is concerned, it does not matter how the regulated parties fund their carbon intensity reductions; rather, what matters is that the regulated parties meet their credit balancing requirements in section 95484 for each compliance period.

With regard to the Scoping Plan, the Scoping Plan is not a regulation in itself, but rather it is the overall roadmap describing the measures to be developed and implemented to help achieve the State's climate change policies and requirements. Therefore, the accounting of GHG reductions achieved by the various Scoping Plan measures (like the LCFS) is entirely up to the individual programs, like the LCFS, that are implemented as part of the roadmap.

C-326. Comment: WSPA believes ARB needs to complete all elements of the regulation before, 1) proceeding with any adoption hearing in the first instance, and 2) requiring regulated parties to initiate efforts to comply. We do not believe it is appropriate for ARB to hold an adoption hearing and then proceed to continue to work major aspects of the regulation in following months in piecemeal fashion.

Examples of items that need much more clarity in order for the regulation to be complete include: recordkeeping and reporting requirements; credit trading details; the role of ARB in credit trading markets; the treatment of high carbon intensity crude oil (HCICO); and confidentiality provisions. Without additional clarity on these issues, our industry still does not have the tools it needs to move forward with compliance efforts.

Reporting requirements begin in four months and our members need to be initiating activity on many aspects of the regulation now, not in 2010. We understand that some elements of the regulation that the Board will need to address will not occur until the spring of 2010. This fails to be an acceptable or admirable rulemaking process. (WSPA4)

Response: The originally proposed regulatory text was modified substantially to provide greater details for the recordkeeping and reporting requirements. These are specified explicitly in section 95484(a), (c), and (d).

With respect to the credit trading provisions and ARB's role, if any, in credit trading markets, these issues were discussed at length in response to Comments C-301 through C-319. In summary, the regulation as adopted provides sufficient requirements and criteria to allow credit transactions to occur between regulated parties and between regulated parties and non-regulated parties (for the limited purpose of exporting for compliance with other GHG reduction programs; see 95485(c)). Such credit transactions can and will occur without ARB playing any role other than to receive specified data about those transactions. And the transactions do not depend on whatever voluntary service role ARB may choose, if any, to enhance credit trading (e.g., to serve as a mere information warehouse or to serve as an active/passive trade facilitator). The Staff Report provides an additional discussion of possible voluntary service roles ARB may choose to play to enhance credit trades (ISOR at V-35, 36).

With regard to the treatment of HCICO, the originally proposed regulatory text was modified substantially in the 2nd 15-Day Change Notice in response to comments

submitted by WSPA. Indeed, the modified language released and shown in double underline (to indicate additions) and double strikethrough (to indicate deletions), as specified in sections 95484(a) and 954869(b)(2), directly reflects the extensive input provided by WSPA and its members.

Finally, with respect to the confidentiality provisions and the treatment of trade secrets, this issue was discussed extensively in response to Comments C-82, C-302, C-303, and C-311. In summary, the regulation as adopted provides explicit language with regard to how data submitted to ARB will be treated under the Public Records Act (Government Code section 6250 et seq.) and ARB's confidentiality regulations (title 17, California Code of Regulations, sections 91000-91022).

Section 95484(c) specifies that all regulated parties must report fuels and other data electronically and on a quarterly and annual basis. While the regulation is slated to become effective on or about January 1, 2010, the first reports are not due until May 31, 2010. Thus, there should be ample time for WSPA members and other regulated parties to complete their reporting and recordkeeping requirements by the time the first reports are due.

D. COMPLIANCE, CREDITS AND ENFORCEMENT

This section addresses comments that relate to the concept of physical pathways, credit banking and trading, and reporting requirements.

Physical Pathways

D-1. Comment: We are also concerned that although ARB intends to rely on the EPA's RIN system, ARB's intended use of RINs is not consistent with the federal RIN program. For example, the proposed regulations specify that a regulated party must report all RINs retired for its facilities in California. The federal RIN program is national in scope and RINs for specific facilities are not "retired." Thus, this provision of ARB's regulation is likely to cause confusion.

While we recognize that the federal RIN system can be a helpful tool in tracking compliance with ARB rules, we believe that the system can be simplified for California and that obligated parties should only be required to demonstrate volumes of the various types of biofuels blended and not specifically track and retire RINs. (SHELL)

Response: Although the use of RINs is associated with a nationwide U.S. EPA Program, the LCFS requirement to report RINs is only intended for the fuels used in California. RIN reporting will provide a broad-level check on fuel supplied from various biorefineries. It also provides some coordination with the federal program with an opportunity for greater integration in the future.

D-2. Comment: A registration program could be developed for importers of fuel into California. The importers are best positioned to satisfy the physical pathway requirements defined in Sec. 95484(d)(2). Similarly, registered importers could be listed in the ARB website providing information to parties requiring low carbon fuels/blend stocks. (WSPA1)

Response: The regulation requires the regulated parties—fuel producers and importers—to report the correct physical pathway and carbon intensity of their fuels. It will ultimately remain the responsibility of the regulated parties to supply the correct physical pathway and the carbon intensity of their fuels. That said, the ARB is developing a registration program for facilities that produce biofuels within California or outside of California where the fuels are for use within, or import into, the State. The ARB will be sending out registration materials to all known biofuels companies that could potentially be producing biofuels for use or import. This registration program will facilitate the process of identifying and registering biofuels facilities and will enable regulated parties to reference these facilities in quarterly and annual reports using the "Facility ID". The registration process and establishment of the Facility ID will include a description of the physical pathway and the identification of the carbon intensity provided by the facility owner.

Credit Banking and Trading

D-3. Comment: Section 95481^{*}(b)(3) and (4) allows a regulated party that fails to meet the compliance schedule for a given year another full year to make up its deficit, and the regulated party is not even subject to penalties unless it is more than 10 percent out of compliance. The CNGVC includes a number of companies that will generate credits in the early years of the LCFS. They will do this by incurring significant costs to provide the very low carbon, LCFS-compliant fuels that are the goal of the LCFS. We see no reason why non-compliant parties should not be required to purchase LCFS credits to make up their shortfall – not 12 months later, but upon determination of their shortfall and noncompliance. We urge the Board to amend the final rule to require immediate coverage of any shortfall by the purchase of LCFS credits, provided they are available. (CNGVC1)

Response: It would be inappropriate to incorporate the suggested changes at this time because such a requirement can be contrary to the concept of a freely operating credit-trading market. The LCFS is designed to be operated on free market principles as much as possible. This means that the regulation allows for the issuance of LCFS credits and the trading of such credits as a negotiated, “arms-length” transaction between regulated parties, without forcing regulated parties to conduct such trades.

By contrast, credit prices are likely to spike under the forced-purchase scenario suggested by the commenter, resulting in substantially higher prices than they normally would be. This is because the forced purchase would likely have the adverse effect of putting credit sellers in a superior position where they know that a buyer will be forced to purchase available credits at whatever prices the sellers want. Under those circumstances, would it be appropriate or even feasible to place artificial limits on credit prices? If so, what would be the appropriate price caps and how would we determine them? These are important and significant questions that need to be addressed before the suggested change can be considered.

Thus, the suggested requirement to force regulated parties in a shortfall situation to buy credits available in the market adds complexity to an already complex regulation. Rather than forcing parties in a shortfall to buy credits, we believe that the regulation, as adopted, more appropriately addresses shortfalls by requiring reconciliation within a year, treating two consecutive shortfalls as a major shortfall (irrespective of the shortfall’s magnitude), not permitting two shortfalls in consecutive years, and subjecting major shortfalls to penalties and other remedies permitted under State law.

With that said, the Board in Resolution 09-31 directed the Executive Officer to monitor the implementation of the regulation and propose amendments for the Board’s consideration when warranted. Further, the final regulation requires the Executive

^{*} Note that the commenter referred to “section 95481(b)(3-4).” Because that subsection merely lists the acronyms “CARBOB” and “CaRFG,” we will assume the commenter intended to refer instead to section 95484(b)(3) and (4).

Officer to conduct regulation reviews by 2012 and 2015 (section 95489). The scope of the reviews will include, among others:

- (1) the “LCFS program’s progress against LCFS targets” (section 95489(a)(1));
- (2) the “availability and use of ultralow carbon fuels to achieve the LCFS standards and advisability of establishing additional mechanisms to incentivize higher volumes of these fuels to be used” (section 95489 (a)(5)); and
- (3) the “identification of hurdles or barriers...and recommendations for addressing such hurdles or barriers” (section 95489(a)(11)).

Clearly, further consideration of the commenter’s suggested change falls well within the scope of the formal regulation review. Thus, the Executive Officer may consider and propose amendments in the future that are consistent with the suggested changes, if he/she determines at that time such a requirement is necessary and appropriate.

D-4. Comment: Now, according to the aforementioned paragraph, the use of GHG credits generated outside the LCFS Program is positively disallowed. Such decision needs to be reconsidered. In conclusion, the proposed exclusion of externally generated GHG credits (i.e., marine, aviation, & rail related) must be reconsidered for the purpose of removal from the proposed regulation. (ALEX2)

Response: To keep LCFS credit transactions simple in the early years and to ensure credits came from the transportation sector, the Board decided that GHG credits generated outside the LCFS program should not be allowed for use in the program.

The LCFS is designed to create a lasting market for clean transportation technology, stimulate the production and use of low-carbon transportation fuels in California, and reduce California’s dependence on petroleum. To achieve Governor Schwarzenegger’s long-term goal of reducing GHG emissions by 80 percent by 2050 (Executive Order S-3-05), the carbon intensity of transportation fuels will need to be substantially decreased over the 2020 target of a 10 percent reduction. The LCFS is structured to stimulate more fundamental changes to the transportation fuel pool, moving towards fuels that meet the much lower carbon intensities needed to meet long-term GHG emissions goals. Allowing credits to be imported from outside the transportation sector could preclude achievement of these goals.

The commenter urges the allowance of credits from marine, aviation, and rail-related applications. The regulation does cover fuels used in marine and locomotive applications to the extent those fuels – diesel fuel and gasoline – are currently regulated by ARB (see sections 95480.1(a) and (d), and 95481(a)(42)). As a possible expansion, staff will continue to evaluate the feasibility and effectiveness of allowing credits generated from those marine, aviation, and rail transportation fuels that are not currently included in the LCFS fuel pool to be used in the LCFS program. ARB staff will provide an update on the potential use of GHG credits from lower carbon marine and aviation fuels to be used in the LCFS program, to be performed by 2012 and 2015. Such an

expansion may raise significant preemption issues.

D-5. Comment: Emission reductions that occur within the area of overlap between the LCFS and the greater AB 32 should result in a regulated party taking credit for the reductions in both programs. We have heard ARB staff suggest that a regulated party can only take credit for such reductions in the greater AB 32 program – and not in the LCFS. (BP1)

Comment: Crediting both AB 32 and LCFS compliance as co-benefits for a single action which reduces emissions and AFCI in the area of regulatory interaction also creates greater potential to encourage higher cost, potentially game-changing technologies to be developed and deployed. It creates extra incentive to comply with AB 32 by reducing facility emissions directly rather than through trading or the use of offsets – thereby addressing Environmental Justice concerns of AB 32. (BP1)

Response: The extent to which credit should be given for any overlap between the AB 32 cap-and-trade program and the LCFS is outside the scope of this regulation. Rather, the extent to which such overlap credits can be granted, if at all, is entirely dependent on the design of the cap-and-trade program. Because the cap-and-trade program is in the preliminary stages of development, any comments on the interaction between the LCFS and the cap-and-trade program under development would be mere speculation. At this time, the only provision in the LCFS regulation that is relevant to this issue is the LCFS' allowance of credits to be exported to, but not imported from, AB 32-type programs. Section 95485(c)(1) and (2).

D-6. Comment: Pollution trading in the LCFS makes this worse. Refiners of dirtier oil would buy emission “allowances” for the part of their pollution that the LCFS detects. Refiners of corn ethanol, because they have the market and infrastructure advantage, would sell most of these emission “credits.” Dirtier oil investments get a kind of protection: corn refiners get money to invest. Dirtier oil refining infrastructure and pollution trading thus interact to selectively favor – and finance – the dirtiest of replacement fuels for today's oil. Having missed other impacts of the impending switch to dirtier oil, the LCFS does not analyze this impact either. (CBE1)

Response: Contrary to the commenter's claim, the LCFS is designed to create incentives that will encourage fuel providers to use greater volumes of “cleaner” replacement fuels for today's petroleum-based fuels. This is made possible by the use of carbon-intensity based Lookup Tables (to rank fuels relative to their full lifecycle GHG contributions) and allowing regulated parties to trade credits.

Credit trading is a cornerstone of the LCFS program. Through credit trading, fuel providers and other regulated parties will have the incentive, and the mechanism for realizing those incentives, to use lower carbon-intensity alternative fuels (i.e., fuels that are not conventional gasoline or diesel fuel). As such, credit trading provides a

foundation in which lower carbon fuels, such as biofuels derived from waste, are incentivized through market channels.

As discussed in the Staff Report at V-1, the LCFS is based on a system whereby credits, which are generated from fuels with lower carbon intensity than the annual carbon intensity standards, balance the deficits that result from the sale of fuels in California that have higher carbon intensity than the annual carbon intensity standards. A regulated party would meet the carbon intensity requirements if its credits at the end of the year are equal to, or greater, than its deficits. Credits and deficits are determined based on the amount of fuel sold, the carbon intensity of the fuel, and the efficiency by which a vehicle converts the fuel into useable energy. Credits may be retained and traded by regulated parties within the LCFS market to meet their obligations.

In Resolution 09-31, the Board found that the approved regulation, with its foundation based on credit trading, was developed using the best available economic and scientific information. Accordingly, the Board found that the regulation will achieve the maximum technologically feasible and cost-effective GHG emission reductions from transportation fuel used in California. Moreover, through the credit trading and other provisions, the regulation was found by the Board to encourage early compliance with the LCFS compliance schedule.

It is important to note that, in Resolution 09-31, the Board found that the approved regulation meets the criteria set forth in section 38562 of the Health and Safety Code. Among other things, HSC section 38562 requires that the Board, in adopting AB 32 regulations such as the LCFS, design the regulations, including the distribution of emission allowances where appropriate, in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California, and encourages early action to reduce GHGs. Further, HSC section 38562 requires that the Board, in adopting regulations like the LCFS, ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions. With these in mind, the Board would not have made the findings in Resolution 09-31 unless it was confident that the regulation and its credit trading system would meet the statutory requirements (e.g., not worsen the situation, as suggested by the commenter).

With regard to corn ethanol, its carbon intensity values are shown in Table 6 (section 95486(b)(1)). Based on those values, it is evident that corn ethanol does not provide a significant advantage from a credit perspective. Instead, it is the lower carbon fuels, such as electricity, hydrogen, and biofuels derived without land use impacts that create the biggest benefits and therefore would generate the most credits. Credit trading ensures that these benefits are recognized and encouraged so that these fuels can penetrate the market and, with time, replace today's "dirty oils".

By promoting clean, alternative fuels, the LCFS diversifies California's fuel supply. It expands rather than limits what is sold as transportation fuel and inspires competition

among fuel suppliers. Credit trading, among other flexible compliance options, minimizes compliance costs while driving innovation.

D-7. Comment: Remove pollution trading as a “compliance” option. (CBE1)

Response: See response to Comment D-6.

D-8. Comment: Clean Energy is concerned that §95425 as written limits the purchase, sale, and trading of LCFS credits to regulated parties or a third party acting on behalf of a regulated entity. Clean Energy has made prior comments on this issue and feels that it is in direct conflict with a competing proposal by ARB staff that LCFS credits may be sold to the broader AB 32 Cap and Trade program. (CE1)

Response: Please see responses to Comments D-4 and D-5.

D-9. Comment: Remove trading from LCFS in order to set a clear and strict Low Carbon Fuel Standard within California. LCFS depends on averaging weaker in-state reductions with purchased out-of-state reductions (which are very hard to confirm and enforce). Trading within and outside the state undermines and dilutes a strong standard in California. Also, since other states frequently replicate California rules, setting an instate standard creates a good model for other states to replicate. (CBE3)

Response: See response to Comments D-6, D-8, and section C. The LCFS regulation allows for the exporting of credits to other GHG trading programs, subject to the requirements of those other programs. However, the staff proposal prohibits the imports of credits from other programs outside the LCFS. ARB will continue to evaluate the benefits of appropriate conditions for allowing the exportation of credits outside of the LCFS.

D-10. Comment: Don't sell pollution credits that protect dirty oil investments and violate our rights. (CBE4)

Response: See response to Comment D-6.

D-11. Comment: Do not allow regulated parties to carryover any shortfall of compliance until all the credits on the open market are purchased. (CE1)

Response: The Board approved the shortfall carryover as a compliance flexibility option. The carryover compliance flexibility is only allowed for the one year and the regulated party's deficit must not be more than 10 percent of its compliance obligation. Also, the regulated party may not carry a deficit for two consecutive years.

The deficit reconciliation period is offered to the regulated parties who are no more than 10 percent out of compliance for a given year. By carrying over the deficit, a regulated party is not absolved of the deficit. If the deficit was cleared by purchasing all the

credits on the market in the current compliance period, then the regulated party has met the LCFS requirements. If the deficit was carried over to the next year, then the regulated party must have enough credits to meet both the prior year's deficits and the current year's requirement; effectively a compounding effect of the deficit. A regulated party, to lessen the additional burden, may still choose to purchase available credits on the market.

It is unclear at this time whether forcing the regulated party to purchase available credits before the deficit rollover would truly generate any benefit to the market. Additionally, doing so would create a situation in which compliance depends on the availability of credits on the market, which could be negligible in the early years.

D-12. Comment: Expand the sale of LCFS carbon credits generated to the larger AB 32 cap and trade program to non-regulated entities and require "regulated parties" to purchase all available LCFS credits on the market before allowing that entity to carry over its shortfall of 10 percent or less. (CE1)

Response: See response to Comment D-11.

D-13. Comment: To sum up, Clean Energy asks that: 1. §95425 must be modified to allow for the sale of carbon credits to non-regulated entities under the larger AB 32 Cap and Trade program and other cap and trade programs throughout the country and to enable third parties that are not regulated parties to purchase, sell or trade LCFS carbon credits; and, 2. Modify the ability for any regulated party to carry over any carbon credit compliance shortfall in any given year if carbon credits are readily available on the market for sale. (CE1)

Response: Please see responses to Comments D-4, D-5, D-11, and D-16.

For simplicity, the LCFS will be limited to regulated parties until such a time when the AB 32 Cap and Trade system is more developed and when the LCFS credit trading process has been tested and refined. Allowing non-regulated parties access to LCFS credits increases the possibility of uncertainties or errors and could add greater complexities that do not benefit the program. At the designated program review periods, staff will evaluate whether LCFS credit trading can be expanded to non-regulated parties.

Allowing the shortfall to carry over provides additional time for a regulated party to comply with the LCFS; it does not delete the shortfall. A regulated party may choose to purchase credits after the rollover. Furthermore, the LCFS does not dictate how a regulated party can meet the regulation. It allows for maximum flexibility while meeting the GHG emissions reductions goals.

D-14. Comment: Second, we strongly urge ARB staff and its Board to eliminate the ability for a regulated party to carry over any deficit to the following year if carbon credits are readily available for sale on the open market. Regulated parties

should not be allowed to be out of compliance with the rule for any given year if carbon credits are available for purchase. The final draft regulation should only allow a shortfall of compliance (up to 10 percent or less with the ability to settle this debt in the following year) to a regulated party if the open market is barren of carbon credits for sale. No exceptions should be made on this point. (CE1)

Response: See response to Comment D-11. The LCFS regulation as adopted does not force regulated parties to buy credits in the first year of deficit nor does it set a price or cap on the cost of those credits.

D-15. Comment: In a large-scale market-based program where the LCFS market cannot import but export carbon credits, Clean Energy would like to see third party carbon brokers able to "make a market" for these credits. This type of market making activity tends to increase the liquidity of these credits, stimulate firms to generate these types of credits, and improve price transparency. These activities also tend to make it easier for more companies to meet their compliance obligations under the new LCFS. (CE1)

Response: Please see responses to Comments D-4 and D-5.

D-16. Comment: Allow the export of LCFS carbon credits for sale or purchase as directed under the proposed LCFS regulation to non-regulated parties within the broader AB 32 Cap and Trade Program. (CE1)

Response: A post-hearing modification clarifies that the prohibition on purchases, sales, and trades of LCFS credits by a third party entity that is not a regulated party or acting on behalf of a regulated party does not apply when the regulated party that owns the credits is exporting such credits for compliance with other greenhouse gas reduction initiatives. (section 95485(c)(1)(B)). Otherwise, section 95485(c)(1)(C) provisions authorizing export of credits could be ineffectual.

D-17. Comment: Clean Energy is concerned that section 95425 as written limits the purchase, sale and trading of LCFS credits to regulated parties or a third party acting on behalf of a regulated party. Clean Energy has made prior comments on this issue and feels that it is in direct conflict with a competing proposal by ARB staff that LCFS credits may be sold to the broader AB 32 Cap and Trade program. It is therefore unclear if ARB's reluctance to allow for credits to be sold to non-regulated parties under section 95425 is out of concern for refiners who may fail to generate the necessary carbon credits to comply with the LCFS or for another unforeseen reason by Clean Energy. Clean Energy and the Low Carbon Fuels Industry holds another fear that the refiners will resist purchasing our credits at all and will hold us hostage, even drive down the price of the credits by holding out, as the last thing a refiner would want to do in a market they largely monopolize is to provide capital to their competition.

That said, Clean Energy believes that the current language under section 95425 could stifle the development of a proper trading market for LCFS credits. Clean Energy would like to see third party carbon brokers able to “make a market” for these credits. This type of market making activity tends to increase the liquidity of these credits, stimulate firms to generate these types of credits, and improve price transparency. (CE1)

Response: For purposes of this comment, we will assume the commenter intended to refer to section 95485 (particularly section 95485(c)). This is because the approved regulation does not contain a section 95425.

The primary reason why LCFS credit trading generally is restricted to regulated parties under section 95485(c) is to help ensure that reductions in carbon intensity actually occur in the transportation fuels sector. As discussed in Staff Report at ES-1, one of the primary goals of the LCFS program is to stimulate the production and use of alternative, low-carbon fuels in California. The functioning of the LCFS program is dependent on a robust market in which credits are traded regularly between regulated parties. Therefore, if a significant amount of trading occurs between regulated parties and non-regulated parties (e.g., exporting to parties outside of the LCFS), there would be fewer credits available for purchase by regulated parties, and it would be less likely to achieve the goal of stimulating the production and use of low-carbon fuels.

Similarly, the robust trading of credits within the LCFS market is less likely to occur if non-regulated party brokers are allowed to buy and sell LCFS credits. There are at least two reasons for this. First, it is difficult to control the trading of LCFS credits once they reach the secondary trading market (i.e., trading between non-regulated parties). The recent market collapses involving transactions of instruments, such as credit default swaps between non-principals, provide clear lessons on the need to regulate secondary markets. Also, allowing the sale of LCFS credits to non-regulated parties opens up the possibility that such parties may choose to retire those credits rather than making them available on the LCFS market. Retirement of such credits by non-regulated parties would reduce the overall supply of credits, which would seem to be counter to the commenter’s goal of stimulating the flow of credits.

Having said that, in Resolution 09-31 the Board recognized that the LCFS credit trading market is an important part of the program and directed staff to continue working with stakeholders to develop any needed credit trading provisions. Further, section 95489 mandates two program reviews by 2012 and 2015, which can encompass a review of the credit trading that occurs before those reviews and identify any improvements that can enhance credit trading. If the Executive Officer or the advisory panel established pursuant to section 95489 identifies a need to allow credit trading to non-regulated parties and brokers, the Executive Officer can propose appropriate modifications to the LCFS regulation at that time.

D-18. Comment: Further, the ability for "regulated parties" that are out of compliance to carryover their shortfall of 10 percent or less to the following year without being

forced to buy carbon credits that are available on the market will harm the low carbon fuel industries' ability to grow the market. Current ARB proposal plays heavily in the favor of the refiners who want to avoid giving any capital to their competition: the Low Carbon Fuel Industry. Modify the ability for any "regulated party" to carryover any carbon credit compliance shortfall in any given year if carbon credits are readily available on the market for sale. (CE2)

Response: See response to Comments D-11 and D-14.

D-19. Comment: Crediting AB 32 cap and trade refinery GHG reductions to the LCFS is another issue requiring further discussion. Will AB 32 GHG emission reductions be allowed to be used to comply with future LCFS requirements? Will AB 32 reductions be reflected in future default carbon intensity values for gasoline and diesel? Does ARB foresee changing any limitation on the use of excess LCFS credits in complying with the AB 32 requirements? (WSPA1)

Response: Section 95485(c) of the adopted regulation addresses the relationship between the LCFS program and the upcoming AB 32 cap and trade program. To the extent issues remain, they are best addressed when the AB 32 cap and trade program is considered and adopted.

D-20. Comment: Prohibition on near term credit trading between LCFS and AB 32 markets: AQMD staff recommends that the LCFS CI market be carefully tracked before allowing its expansion into the domain of AB 32 emission offset trading, and that future LCFS CI credit trading should be prohibited with the broader AB 32 program until after at least the first five years of LCFS implementation. (SCAQMD1)

Response: The adopted regulation only allows trading of credits out of the LCFS program into the to-be-established AB 32 cap and trade program; it does not permit credits to be imported from the AB 32 cap and trade program. This will not make it any "easier" for regulated parties to comply with the LCFS. We expect that credits will only be traded out if they are less valuable (and less needed) in the LCFS than in the cap and trade program. It should be noted that although the LCFS allows export of the credits to the larger AB 32 cap and trade program, that program is under development and it has not been determined whether the program will allow LCFS credits to enter their market.

Double Counting Credits

D-21. Comment: Why are electricity providers eligible to receive LCFS credits for supplying meters? Other fuel providers will also be required to supply meters to measure fuel volume but will not be able to receive credit. (WSPA1, BP1)

Response: Electricity providers will not receive credit for supplying meters, but rather need to install meters to receive credit for the electricity that they are delivering to

homes for transportation purposes. They must determine the amount of electricity delivered using methods approved by the EO until 2015, after which all electricity delivered must be determined through metering. They are required to supply meters in order to measure fuel volume but do not receive credit solely for supplying meters.

D-22. Comment: Will LCFS credits be adjusted for the Renewable Portfolio Standard (RPS) requirements that electric utilities must meet? Will electric utilities be permitted to use their LCFS credits to meet RPS obligations? (WSPA1, SCAQMD3, SCAQMD2)

Comment: Plug-in hybrid vehicle (PHEV) and Electric Vehicle (EV) credits should not be double counted as both LCFS credits and as offset credits for compliance with the RPS established by the California Public Utilities Commission (CPUC). Full compliance with the 20 percent RPS standard in 2010 is somewhat uncertain at this time. The full benefits of both the LCFS and the RPS program are essential to meet the goals of AB 32, as well as the Scoping Plan adopted by ARB. Accordingly, before PHEV LCFS credit is provided for trading purposes, full compliance with the 2010 standard, as well as the Governor's goal of 33 percent RPS in 2020, should be required distinct from LCFS compliance. The integrity of both the LCFS and the RPS standards is essential and should not be compromised by LCFS credit trading. Furthermore, worse case and best case PHEV recharging scenarios should be examined. AQMD staff recommends that double counting of PHEV or EV credits be prohibited under the LCFS. (SCAQMD1)

Response: The LCFS as approved in Resolution 09-31 requires program reviews in 2011 and 2014 to include regulation language and adjustments if necessary. The LCFS allows credits to be exported. ARB must ensure there is no double counting of emission reductions. However, the use of these credits must be determined by the design of the other programs (RPS, ZEV Mandate, etc.).

D-23. Comment: Credits should be available under both AB 32 and the LCFS for the same action. (BP1)

Response: The AB 32 cap-and-trade program is currently under development, and therefore the LCFS contains a placeholder section in which the cap-and-trade provisions would eventually be specified. At this time, the LCFS regulation would allow the export of LCFS credits to the AB 32 programs provided there is an AB 32 program mechanism to accept those credits, but would prohibit the import of cap-and-trade allowances into the LCFS program.

D-24. Comment: Also it seems at this point, and perhaps you can confirm it, that despite the discussions at the March 27 workshop, there really has been no staff analysis of how the assumptions made regarding the sale of FFVS, PHEVs, BEVs and FCVs under the LCFS impact the emission benefits already claimed for the AB1493, ZEV, and LEV II regulations. (SIERRAR)

Comment: ARB has said an adjustment will need to be made to the AB 32 Scoping Plan due to the double crediting of electricity GHG reductions for the AB 1493 Pavley regulations. ARB also needs to describe clearly how those adjustments will be made and how they intend to make consistent changes for any double-crediting between the LCFS, Pavley, and AB 32 programs for other fuels. (WSPA1)

Response: Staff working on the LCFS developed the vehicle projections with the staff responsible for implementation of the ZEV, LEV, and Pavley (AB 1493) regulations, and with input from inventory staff. The LCFS compliance scenarios were generated for both the existing ZEV regulation and for a future “improved ZEV regulation.” The LCFS compliance scenario baseline was adjusted to reflect the vehicle fuel economy improvements under Pavley (AB 1493), and the associated greenhouse gas benefits were credited to Pavley (not LCFS). The estimated LCFS greenhouse gas benefits were further reduced by 10 percent to account for any additional overlap in benefits between the LCFS and the LEV/ZEV/Pavley regulations. FFVs are regulated under the LEV and Pavley regulations and thus were part of those adjustments. Staff also looked at fleet turnover and confirmed that FFV population projections were achievable. Staff will continue to work together and track vehicle population and interaction between the regulations as the LCFS is implemented and the ZEV, LEV, Pavley and LCFS regulations are updated.

In addition, EPA launched SmartWaySM in 2004 – an innovative brand that represents environmentally cleaner, more fuel efficient transportation options, which result in significant, measurable air quality and/or greenhouse gas improvements while maintaining or improving current levels of other emissions and/or pollutants. Also, California state law (Senate Bill 375 (SB 375), Statutes of 2008) requires ARB to set regional targets for the purpose of reducing greenhouse gas emissions from passenger vehicles, for 2020 and 2035. If regions develop integrated land use, housing and transportation plans that meet the SB 375 targets, new projects in these regions can be relieved of certain review requirements of the California Environmental Quality Act. The targets apply to the regions in the State covered by the 18 metropolitan planning organizations. The estimated emission reductions associated with Both SmartWay and SB 375 were taken out of the baseline so that they will not be attributed to the LCFS.

Request to Be Able to Generate Credits

D-25. Comment: The commenter supports allowing electric utilities to earn credits in order to use the revenue from the sale of credits to pay for costs associated with the additional electricity load. (SCPPA)

Response: The LCFS regulation enables regulated parties for electricity to generate LCFS credits; it does not stipulate how the parties would use revenue from the sale of LCFS credits. The CPUC has the authority to regulate electric utilities and is currently considering a rulemaking that addresses the use of LCFS credit revenue, among other

issues. ARB staff will continue to work with CPUC and other interested parties as the rulemaking process continues. See also response to Comment D-27.

D-26. Comment: Oil refiners generate electricity which may be provided to the grid. Can refiners receive LCFS credit for this electricity? (WSPA1, BP2, BP1)

Response: Oil refiners could receive LCFS credit for electricity as a transportation fuel if they become a load serving entity, or other provider of electricity services, or provider of electric charging equipment, as provided in section 95484(a)(6).

D-27. Comment: Why are LCFS credits available to electricity providers when they are already mandated to provide electricity to customers? (WSPA1)

Response: To achieve the goals of the LCFS, credits are available to regulated parties who provide transportation fuel to California which is of lower carbon intensity than gasoline. The availability of credits will promote the use of electricity as a transportation fuel. With that said, in Resolution 09-31 the Board directed staff to continue working with the California Public Utilities Commission, electric utilities, oil refiners, and other stakeholders to review the provisions applicable to regulated parties for electricity and propose amendments.

D-28. Comment: ARB should adopt a resolution to develop a mechanism to allow LCFS credits from new applications of electric forklifts and similar electric non-road vehicles and equipment and to further increase market penetration in existing applications, and return to the Board with recommended regulatory revisions, as appropriate by December 2009. (ALA2)

Response: On April 23, 2009, the Board directed staff to evaluate the feasibility of allowing LCFS credits from new applications of electric forklifts and similar electric non-road vehicles and equipment. Staff started that process on August 5, 2009 and will continue working with stakeholders to develop that mechanism.

Reporting Requirements

D-29. Comment: Several issues concerning enforcement have been discussed briefly by ARB but not resolved. For example, what level of accuracy will ARB need in order to enforce the LCFS standards, including the percent reduction in CI as it relates to all the various fuels that will be subject to the LCFS? (WSPA1)

Response: The regulation is quite explicit in terms of the significance levels by which required data must be reported. Section 95484(c)(5) provides that a regulated party must report the following quantities as specified for those fuels subject to the LCFS:

“(A) *carbon intensity, expressed to the same number of significant figures as shown in the carbon intensity lookup table (Method 1);*

- (B) *credits, expressed to the nearest whole metric ton CO2 equivalent;*
- (C) *fuel volume, expressed as follows:*
1. *a fuel volume greater than 1 million gasoline gallon equivalent (gge) must be expressed to the nearest 10,000 gge;*
 2. *a fuel volume between 100,000 gge and 1 million gge, inclusive, must be expressed to the nearest 1,000 gge;*
 3. *a fuel volume between 10,000 gge and 99,999 gge, inclusive, must be expressed to the nearest 100 gge; and*
 4. *a fuel volume less than 9,999 gge must be expressed to the nearest 10 gge.*
- (D) *any other quantity not specified in section 95484(c)(5)(A) to 95484(c)(5)(C) must be expressed to the nearest whole unit applicable for that quantity.*
- (E) *Rounding Intermediate Calculated Values.*

A regulated party must use one of the following procedures rounding intermediate calculated values for fuel quantity dispensed, blended, or sold in California; calculated carbon intensity values; calculated LCFS credits and deficits; and any other calculated measured quantity required to be used, recorded, maintained, provided, or reported for the purpose determining a reported under the LCFS regulation (17 CCR section 95480 et seq.):

1. *ASTM E 29-08 (Standard Practice for Using Significant Digits in Test Data to Determine Conformance with Specifications), which is incorporated herein by reference;*
2. *Any other practice that the regulated party has demonstrated to the Executive Officer's written satisfaction provides equivalent or better results as compared with the method specified in subsection 95484(c)(5)(E)1. above."*

With regard to report the percent reduction in carbon intensity, there is no such requirement in the regulation as approved.

D-30. Comment: This enforcement issue regarding the level of accuracy that is needed in order to enforce the LCFS standards needs to be part of the discussion before the LCFS rules are adopted not afterward. As such we encourage that future workshops deal with such enforcement issues specifically.

WSPA has several issues concerning how ARB is enforcing its current rules that need to be included in this discussion. (WSPA1)

Response: The ARB has held additional workshops where the Enforcement Division was represented and ARB staff and management were available to address enforcement related questions. The enforcement of the LCFS requirements will be assisted by the LCFS Reporting Tool, which is an online web application that is nearing completion. A workshop to discuss this Tool with ARB SSD and Enforcement Division staff and management was held on August 5th, and all parties on the “LCFS” listserv were invited to attend. There are additional workshops planned in the near future for the Tool that will include staff from the ARB Enforcement Division.

D-31. Comment: WSPA is concerned about the assignment of responsibility to the fuel provider to somehow be knowledgeable about a fuel’s end use so as to make the choice of applicable standard (gasoline or diesel) clear to ARB. WSPA recommends ARB (including Enforcement Division personnel) hold further discussions with the industry on this point. (WSPA1)

Response: Gasoline and diesel fuel providers do not need to know the fuel’s end use; the end use is designated. The same is true for their blend components (ethanol, biomass-based or renewable diesel). For light/medium-duty vehicles (LDV/HDV), the gasoline CI applies. For heavy-duty vehicles (HDV) and off-road vehicles, the diesel CI applies. The regulated parties report the volume of gasoline and diesel for which they have a compliance obligation along with the corresponding CI.

In the regulation, alternative fuels (electricity, CNG, hydrogen) for light/medium-duty applications use the gasoline standard and are referred to as “gasoline-substitutes.” Those alternative fuels used for heavy duty/off-road applications use the diesel standard and are referred to as “diesel-substitutes.” A regulated party that provides an alternative fuel such as electricity, CNG, LNG or hydrogen or hydrogen blends will need to report the amount of fuel dispensed or metered for all LDV/MDV and all HDV per compliance period. Alternative fuels will use either the gasoline or diesel standard for reporting purposes, depending on how the fuel is used in the vehicle (LDV/MDV or HDV).

D-32. Comment: WSPA members are concerned with the proposed requirement for quarterly reports as required by section 95424(c)(3). Quarterly reports could be onerous and may be unnecessary. ARB needs to provide additional reasons for why such reports are necessary and why annual reports are not sufficient. (WSPA1)

Comment: The Reporting Requirements Should Be Simplified and Clarified. In section 95484, ARB proposes to require quarterly reporting. Shell believes that such frequent reporting is not necessary and that annual compliance reporting is sufficient. In addition, we request that ARB reconsider the deadlines for reporting given similar reporting requirements under U.S. EPA’s renewable fuel standard

rule. Given the limited resources available within companies to file such reports, it would be very helpful if ARB would adjust the deadlines by two months to reduce the overlap with EPA requirements. (SHELL)

Comment: As commented previously, ConocoPhillips sees the proposed requirement for quarterly reporting as unwarranted and burdensome. ARB has not justified the benefit of this new reporting burden on industry. As the LCFS is an annual program, the Agency should not require reporting more frequently than annually. (CONOCO)

Response: The quarterly progress reports are intended to ensure that regulated parties keep track of their ability to comply with the allowable carbon intensity at the end of the annual compliance period. They are used to gauge progress and for credit generation from the information and data, such as carbon intensities, fuel volumes sold or dispensed. Beginning in 2011, regulated parties can start generating credits on a quarterly basis from data submitted quarterly. For consistency, the quarterly reporting frequency is the same as for the U.S. EPA Renewable Fuels Standard (RFS) Program.

The LCFS requires that beginning in 2010 and each year thereafter, a regulated party must submit quarterly progress reports to the Executive Officer by the end of the second month after the quarter in which the transactions occurred. This is the same quarterly compliance reporting as being proposed for the RFS. The LCFS provides two additional months before the annual report is due beyond RFS. The annual reporting deadline is April 31st for LCFS. The EPA RFS annual report is due by February 28th. A regulated party may “submit” their annual LCFS report prior to April 31st, if desired. The only requirement is that the fourth quarter report must have been submitted previously. The quarterly reports will be used to generate the annual report within an online LCFS reporting application. The regulated parties will be able to review for accuracy before approving annual report submittal. This is intended to make the annual reporting process less onerous for the regulated parties.

D-33. Comment: These federal [RFS] rules do not classify deficit carry forwards as non-compliance. ARB should clarify that it does not intend to limit the ability of regulated parties to clear the deficit only through the use of either carryover credits or by purchasing credits from others. ARB should clarify that they also intend to allow regulated parties to clear the deficit by over complying in the second year and generating excess credits. (SHELL)

Response: The LCFS enables regulated parties to carry forward deficits and comply the next year by generating excess credits in the case of a Small Credit Balance Shortfall (“In Deficit”). As specified in section 95484(b)(3) and (4), if a regulated party has not generated, acquired, or carried over sufficient LCFS credits to meet its obligation for the given compliance period, the regulated party is in “deficit” status (not in violation) if the following conditions are met:

- The regulated party has not incurred a negative credit balance in the previous

compliance period, and

- The total credits in the account must be at least 90 percent of the total deficits for the current compliance period.

The regulated party meeting the two conditions above may carry over the negative credit balance from one compliance period to the next compliance period automatically without incurring a penalty. This is a compliance flexibility provision that is similar to what is allowed under the federal RFS2. The regulated party has until December 31 of the next compliance period to clear the carried-over negative credit balance. For example, if a regulated party incurred a negative credit balance of -100 MT in 2012 but was in compliance in 2011 and has a credit to deficit ratio of 95 percent in 2012, the regulated party may carry over the -100 MT to 2013 automatically without incurring any penalties. During 2013, the regulated party must clear the -100 MT and meet the obligations of 2013.

Conversely, if a regulated party has met one of the conditions below which is a Large Credit Balance Shortfall (“In Violation”), then the regulated party is considered to be in violation of the LCFS and subject to the penalties and enforcement actions authorized under section 95484(e):

- Incurred a negative credit balance for two or more consecutive years; or
- Incurred a credit to deficit ratio of less than 90 percent for a given a compliance period.

The approved regulation with modifications is explicit in how regulated parties can clear deficits: by retirement of an equal amount of retained credits, by purchase of an equal amount of credits from another regulated party, or by any combination of these two methods. Section 95484(b)(4)(A) and (B).

D-34. Comment: The (c)(3)(A)(1) Quarterly Reporting: requires the regulated party to provide to the Executive Officer”...the product transfer document...”. It would be helpful if ARB made it clear that what they want is the information from the product transfer document not a copy of the actual document. (WSPA1)

Comment: ARB’s proposed reporting requirements include providing the Executive Officer with copies of product transfer documents (PTDs) when transfer of compliance obligation occurs. The Agency should not require physical copies of PTDs to be provided. Rather, the Agency should build reporting formats that would include information on who the transferee is and retain the right to request documentation if necessary. (CONOCO)

Response: The regulation was modified to require the submittal of PTDs only when requested by the Executive Officer. See section 95484(c)(3)(A). The PTD was intended to be submitted as a pdf file to the LCFS Reporting Tool (RT). An actual copy of the PTD will not be required to be submitted unless otherwise requested by the Executive Officer. The PTDs need to be retained by the regulated parties and available in the case of an audit by the ARB Enforcement Division.

Consideration is being given to providing information from the PTD as part of the reported data replacing the requirement of uploading a .pdf file of the actual PTD. This would be less onerous to the regulated parties but still comply with the intent of the LCFS. The information required from the PTD would include:

- the names and addresses of the transferor and transferee;
- the fuel name and blendstock composition;
- volume of fuel or distillate which is being transferred;
- the CI of the fuel or distillate which is being transferred;
- the location and date of the transfer;
- and the Name/Facility ID of the original fuel producer.

D-35. Comment: Table 4 – We recommend deletion of unnecessary data reporting requirements (component blend data in particular). Also, ARB needs to clarify how and if data can be kept business confidential. (WSPA1)

Response: The commenter appears to be referring to a requirement in earlier versions of the regulation. The regulation was modified so that component blend data is no longer required in the data reporting requirements. The reporting will be limited to the major fuel components (e.g., the volume of ARBOB, Ethanol, Hydrogen, etc., for which the regulated party is obligated.).

The regulated party will submit an annual compliance and quarterly progress report by using an interactive, secure online LCFS Reporting Tool (LRT) under development. The online tool will be designed to provide the necessary level of security to ensure that the data submitted remains business confidential.

Like other data submitted to ARB, data submitted pursuant to the LCFS reporting requirements in section 95484 are subject to ARB's well-established regulations with regard to the treatment of confidential data (title 17, sections 91000—91022, California Code of Regulations) and the Public Records Act (Government Code section 6250 et seq.).

E. LEGAL AUTHORITY

Comments and responses in this section are related to the Board's legal authority to implement an LCFS. It includes the following topics: compliance with AB 32 legal requirements, compliance with California Environmental Quality Act (CEQA), multimedia evaluations, the interstate commerce clause and compliance with the Administrative Procedure Act (APA).

Compliance with AB 32 Legal Requirements

E-1. Comment: The proposed LCFS regulation violates the underlying AB 32 statute requiring no regressive or disproportionate impacts upon low-income and traditionally overburdened communities, for the reasons we have outlined. As a measure under the AB 32 framework, the LCFS must ensure that activities undertaken do not disproportionately impact low-income communities under HSC section 38562(b)(2). (CERA1)

We seek to ensure that the LCFS complies with AB 32's Health and Safety Code (HSC) section 38562(b)(2) requiring that "all activities undertaken to comply with the regulations do not disproportionately impact low-income communities" – a requirement not met by the proposed LCFS regulation. (CERA2)

The LCFS fails to ensure that activities undertaken do not disproportionately impact low-income communities as required by AB 32 (HSC section 38562(b)(2)). (CRPE1)

Response: The referenced AB 32 provision, HSC section 38562(b)(2), provides:

(b) In adopting regulations pursuant to this section and Part 5 (commencing with Section 38570), to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

* * * *

(2) Ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities.

For the reasons given in the responses to the specific comments identified below, we believe that ARB has met this requirement in adopting the LCFS.

E-2. Comment: ARB has not done a proper environmental justice evaluation and has not met its duty to ensure that the LCFS does not disproportionately impact low-income and minority communities. ARB claims that it is developing an approach to consider localized impacts for future rulemaking. It also promises to develop tools, such as a screening method, to aid in the evaluation of the LCFS on disproportionately impacted communities. ARB has committed to develop a

guidance document draft out by the end of December 2009. While all of these commitments to improve the future analysis and develop guidelines are important, they do not absolve ARB from doing an assessment of impacts to the extent feasible now. There are multiple analyses, referenced above, that have enough information to prepare some review of the impacts of the LCFS on disproportionately impacted low-income and minority communities. ARB has failed to do any environmental justice analysis, continually postponing review until sometime in the future. Meanwhile, communities of color and low-income communities are being disproportionately impacted by the decisions made now. An environmental analysis is not just important to protect these vulnerable communities; it is required by AB 32 before ARB can approve this regulation. (CRPE1, CRPE2)

Response: Other analyses conducted by ARB in the LCFS rulemaking substantially overlap with environmental justice considerations. Overall, the Board has found that the LCFS regulation is expected to result in no significant additional adverse impacts to California's statewide air quality due to emissions of criteria and toxic pollutants; based on the best available data, there may be a benefit in further reducing criteria pollutants from the 2020 projected vehicle fleet. But despite the overall benefits, there still can be localized effects that could disproportionately impact low-income communities. The one instance identified by staff in which localized effects are anticipated involves the possible construction and operation of 25-30 new biofuel production facilities in the state by 2020. Many of these new facilities could be built in the Central Valley.

Staff conducted a health risk assessment to estimate the potential localized cancer risk associated with a worst-case scenario in which 3 collocated biorefineries become operational. The primary cancer risk would come from increased emissions of diesel PM from trucks servicing the facility. The greatest impact from onsite emissions from the 3 collocated biorefineries was estimated to be the area surrounding the facility fence lines with a potential cancer risk of approximately 0.4 chances in a million. The health risk assessment also examined combined onsite and offsite emissions from the 3 facilities; the offsite emissions result from an estimated 330 truck trips daily on a main shared truck route. The area with the greatest impact – mostly occurring along the main truck route – has an estimated cancer risk of over 5 chances in a million. The estimated cancer risk is about 2 chances in a million surrounding the individual truck routes within about 300 yards. At about 500 yards from the truck routes, the estimated cancer risk decreases to about 1 chance in a million.

Since the elevated cancer risks depend on the existence of neighbors in close proximity to the biorefinery facilities, the siting of the facilities is an important factor in determining whether their emissions could disproportionately impact low-income communities. In Resolution 09-31, the Board directed the Executive Officer to work with local air districts, regulated parties, environmental advocates, public health experts and other stakeholders to develop a "best practices" guidance document for use by siting authorities when they are considering the siting of biofuel and other fuel production facilities in California to assess and mitigate the air quality impacts of these facilities and

present the guidance document to the Board by December 2009. The best practices are expected to include evaluation of the proximity of the new facilities to and impacts on local communities and particularly low-income communities. In the Resolution the Board also directed the Executive Officer to participate in the environmental review of specific projects in California directly related to the production, storage and distribution of transportation of fuel subject to the LCFS program, including the evaluation of the air quality impacts of the projects and, as appropriate, the identification of feasible measures to mitigate the local and regional impacts of the projects.

We believe that the health risk assessment conducted by staff, coupled with other analyses and the commitments to prepare a best practices guidance document that would cover the siting of new biofuel facilities and to participate in project environmental reviews, satisfies the requirements of HSC section 38562(b)(2).

E-3. Comment: Given the considerable public health risks of switching and mixing fuel blends, with often unknown or controversial results in localized communities, a full environmental justice impact assessment is warranted for each fuel type, blend, and known impact on low-income communities. (CERA1)

Response: With respect to impacts on low-income communities from the siting of new biofuel production facilities, see the response to the previous comment. With respect to the effect of switching and mixing fuel blends on motor vehicle emissions, see the discussion on pp. VII-17 to VII-21 of the Staff Report and Appendices F6-F9.

E-4. Comment: The proposed LCFS regulation violates HSC section 38562(b)(2) because the siting of biorefineries will disproportionately impact communities already adversely impacted by air pollution. The regulation will incentivize corn-based ethanol and ethanol biorefineries in California. These refineries will be sited in the San Joaquin Valley, where they will increase pollution from processing, exacerbate water shortages, and increase truck and rail transportation fueled by toxic-emitting coal and diesel in an area that already competes for the worst air in the nation. (CERA1 [EJAC] [pp.3-4])

Response: We fully acknowledge that the LCFS program is likely to result in the construction of new biofuel production facilities (estimated up to 25-30) and that many could be sited in the San Joaquin Valley. Overall, the Board has found that the LCFS regulation is expected to result in no significant additional adverse impacts to California's statewide air quality due to emissions of criteria and toxic pollutants; based on the best available data, there may be a benefit in further reducing criteria pollutants from the 2020 projected vehicle fleet. But despite the overall benefits, there still can be localized effects that could disproportionately impact low-income communities.

The fact that there could be some localized emissions increases in a nonattainment air basin inhabited by a significant number of low-income persons does not necessarily mean the LCFS regulation will disproportionately impact low-income communities. Rather the key element for examination here is whether the very localized health

impacts would adversely impact low-income communities in the vicinity of the new biofuels facilities, and this depends largely on the siting of the facilities. With respect to siting of the facilities, see the response to E-2.

E-5. Comment: Biorefineries create disproportionate public health risks in overburdened communities, as shown in the health risk assessment in the ISOR. This assessment indicated that the area with the greatest health risk impact was estimated to be the area surrounding the facility fence lines with a potential cancer risk of over 0.4 chances in a million. The analysis also shows that the statewide health impacts of the emissions associated with these biorefinery facilities are approximately 24 premature deaths, 8 hospital admissions, and 367 cases of asthma, acute bronchitis and other lower respiratory symptoms. (CERA1)

Response: The highest potential cancer risk of over 0.4 chances per million from onsite emissions for the area surrounding facility fence lines in the worst-case scenario of three collocated prototype biorefinery facilities is appropriately viewed in the context of background risk levels. The existing San Joaquin Valley Air Basin background risk is estimated to be about 390 in a million caused by diesel PM and about 590 in a million caused by all toxic pollutants in 2000. The extent to which biorefinery emissions could disproportionately impact low-income communities depends largely on the siting of the facilities, which is discussed in responses to previous comments.

E-6. Comment: ARB did not evaluate the cumulative impacts around biorefineries in violation of HSC section 38570(b)(1), which requires that in any market-based mechanism ARB shall “consider the potential for direct, indirect, and cumulative emissions impacts from these mechanisms including localized impacts in communities that are already adversely impacted by air pollution.” ARB has not addressed several potentially significant direct, localized, and cumulative impacts from biorefineries including localized diesel PM impacts and localized facility emissions impacts. (pp. 4-5) The biorefineries would be constructed in the San Joaquin Valley, where Kern County already bears a disproportionate burden of air pollution from numerous sources. Residents already live with pollution from a large portion of the state’s oil production, hundreds of daily trips bringing sludge and garbage from the South Coast Region to 3 different dump sites in Kern County, and soon, floods of extra traffic relieving the Port of Oakland and LA Ports once a huge bi-modal transfer station and International Trade and Technology is constructed as an inland port. These cumulative impacts must be weighed when promulgating a policy that will directly encourage and incent the siting of additional sources of air pollution. ARB staff’s only suggested strategy to address the disproportionate siting of biorefineries in low-income and traditionally disadvantaged communities is a commitment to develop a guidance document that is nonexistent and will be merely advisory. (CERA1)

Response: The referenced AB 32 provision, HSC section 38570(b)(1), provides:

(b) Prior to the inclusion of any market-based compliance mechanism in the regulations, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

(1) Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution.

The health risk assessment conducted by staff and described in Appendix F had the effect of accounting for cumulative and localized impacts that may occur in the San Joaquin Valley because it conservatively analyzed the impacts of three biorefineries located only 500 meters apart from each other. The UC Davis biofuel supply modeling work assumes that biorefineries to be at least 50 miles apart, since each facility would need biomass feedstock supply from that area. Therefore the three collocated biorefinery facilities represent a worst case scenario for the most conservative estimate (pp. F-64, F-70), akin perhaps to a single biorefinery facility locating near new facilities or activities of other types.

The health risk assessment of the three prototype biorefinery facilities identified areas with the greatest impact from onsite emissions having an estimated potential cancer risk of over 0.4 chances in a million, surrounding the facility fence lines. The estimated cancer risks decrease to about 0.2 and 0.1 chances per million at about 200 yards and 400 yards respectively from the facility boundaries surrounding the facility fence lines. When onsite emissions are combined with offsite emissions from increased truck trips of 330 a day, the area with the greatest impact has an estimated potential cancer risk of approximately 5 chances in a million. The estimated cancer risk is about 2 chances in a million surrounding the individual truck routes within about 300 yards. At about 500 yards from the truck routes, the estimated cancer risk decreases to about 1 chance in a million. These cumulative impacts from the 3 collocated biorefinery facilities compare to the existing San Joaquin Valley Air Basin background risk estimated to be about 390 in a million caused by diesel PM and about 590 in a million caused by all toxic pollutants in 2000. (p. F-68)

E-7. Comment: The LCFS must ensure that activities undertaken do not interfere with state and federal efforts to reduce toxic emissions under HSC section 38562(b)(4). HSC section 38562(b)(6) requires the ARB to consider “overall societal benefits, including reductions in other air pollutants.” In addition, HSC section 38570(b) (2) requires ARB to “Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria pollutants.” (CERA1)

While the ISOR states the LCFS is expected to result in no additional adverse impacts to California’s air quality due to emissions of criteria and toxic air pollutants, staff is still evaluating toxic air pollutant emissions. Because ARB analysis is incomplete, ARB staff cannot claim that the LCFS will not increase

toxic and criteria pollutant emissions as statutorily required. (CERA1)

ARB should delay adoption if the LCFS until 2015 or ARB staff can guarantee that there will be no disproportionate impacts on low-income communities and all analyses are complete. (CERA1)

Additional research needs to be conducted on the various fuel type varieties and blends in order to ensure compliance with AB 32 no-backsliding statutory requirements. If any fuel type increases toxic emissions, it is required by statute to fail and should not receive credit under the LCFS. (CERA1)

Response: The referenced AB 32 provisions, HSC section 38562(b) (4) and (6), provide:

(b) In adopting regulations pursuant to this section and Part 5 (commencing with Section 38570), to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

* * * *

(4) Ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions.

* * * *

(6) Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment and public health.

There are currently sufficient data in the Staff Report and Appendix F to justify ARB's determination that the LCFS is not expected to increase toxic, as well as criteria, air pollutants. We have not received any public comments showing that staff's analysis is invalid.

With respect to additional research on fuel types and blends, HSC section 38562(b)(4) does not require that every fuel must be shown not to increase toxic emissions. ARB's determination is based on the expected aggregated emissions associated with from all participating fuels, relying on currently available data. ARB plans to continue its evaluations and is prepared to conduct a rulemaking to establish any additional specifications needed to limit emissions.

The Staff Report and Appendix F provide a cancer health risk assessment and a health impacts assessment of projected diesel PM and PM2.5 emissions associated with three new biorefineries. Table VII-3 in the Staff Report provides a summary of potential 2020 changes from the production and use of low carbon fuels above the baseline. The

change in PM2.5 emissions from each listed source is either none or a negative value, with the one exception being a small increase in PM2.5 emissions from in-state biorefinery truck and rail trips. Also see Attachment A of this document for the updated health impacts and the Peer Review section for updated information regarding E85 toxics compared to gasoline.

E-8. Comment: Because increases in food prices disproportionately impact low-income people, the inclusion of food crops in the LCFS will violate AB 32's unequivocal requirement that actions taken to meet AB 32 goals do not disproportionately impact low-income communities. Thus in order to meet AB 32 statutory provisions, ARB must exclude crop-based biofuels despite, in several instances, seeming to pick it as a fuel "winner." (CERA1)

ARB does not address the disproportionate impact that increased food costs would have on low-income communities. (CRPE1)

Response: For the actual text of the statutory requirement regarding disproportionate impacts on low-income communities see the response to E-1.

The potential impact of the use of food crops in the LCFS program on food prices is an important part of a broader effort to assure that the use of biofuels in the program will be sustainable. At this time there is not enough information available on the impact of the use of biofuels on food prices or specific strategies that may be appropriate to address those impacts. In Resolution 09-31 the Board directed the Executive Officer to work with stakeholders to present a work plan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS program; those provisions are to be finalized no later than December 2011 unless the Executive Officer determines that such actions are not feasible and not appropriate. We believe this time frame should be sufficient to avoid disproportionate impacts on low-income communities.

E-9. Comment: AB 32 requires emission reductions to be "real, permanent, quantifiable verifiable, and enforceable" under HSC section 38562(d)(1), and we do not believe that the lifecycle analysis issues have been resolved with the requisite level of certainty to meet this requirement. (CERA1, CERA2)

The proposed default and opt-in system will undermine the achievement of "real" emission reductions. (CERA2)

Response: The lifecycle analysis issues are discussed in the responses to comments in section K. A number of environmental organizations – including NRDC, UCS and the Sierra Club – support the lifecycle approach taken in the regulation. Although we expect that improvements in the analysis will be achieved in the future, the lifecycle analysis is at this time sufficiently robust to justify proceeding with the regulatory program.

The default values for gasoline and diesel fuel are designed to reduce the use of compliance by crude switching, which would seriously threaten the overall achievement GHG emission reductions. For alternative fuels, the default values simply provide a practical system for identifying fuel carbon intensity while allowing regulated parties flexibility in modifying operations to achieve carbon intensity reductions.

Similarly, the opt-in system should not reduce the achievement of “real” emission reductions. The only fuels identified in section 95480.1(b) as qualifying for the opt-in mechanism are alternative fuels that are presumed to have a full fuel-cycle carbon intensity that meets the LCFS compliance schedules through the end of 2020. The expected effect of the opt-in mechanism is that potentially fewer regulated parties will claim credits for these fuels than would be the case under a mandatory system for all transportation fuels. The overall reduction in credits would be expected to increase rather than decrease overall GHG emissions reductions.

E-10. Comment: We oppose any pollution trading scheme because it will potentially create “hot-spots” in communities historically overburdened by pollution, because it will create disproportionate impacts on low-income communities, will not achieve real, permanent quantifiable, verifiable, not enforceable pollution reductions as required under AB 32 and prevents public participation.

The market mechanisms in the LCFS must not increase toxic and criteria pollutants under HSC section 38570(b) (2), while HSC section 38562(b)(6) requires ARB to consider “overall societal benefits, including reductions in other pollutants.” Thus in designing the LCFS program, the ARB must consider that credit trading will maintain or exacerbate the air pollution problems already in Californian communities, or at the very least, not reduce the problems as fast as it otherwise would by simply requiring entities to meet the intensity requirement. (CERA1)

Response: The credit trading only applies to greenhouse gas emissions and not to criteria and toxic emissions. Since global warming is not a local impact, it cannot have hot spot effects.

E-11. Comment: Carbon capture and storage technologies (CCS) do not represent “real” and “permanent” emission reductions and may disproportionately impact low-income or traditionally overburdened communities. We greatly oppose the inclusion of any CCS technologies in the LCFS, whether related to the transportation sector or not. (CERA1)

Response: CCS, if done correctly, can represent “real” and “permanent” emission reductions. Any CCS project in California will be subject to CEQA and local permitting requirements where the issues identified can be addressed. Additionally, the only reference to CCS in the regulation is in section 95486(b)(2)(A)2.c.. Under this provision, a regulated party may, with Executive Officer approval pursuant to section 95486(f), use the Lookup Table for CARBOB, gasoline or diesel fuel produced from high

carbon-intensity crude oil not included in 2006 California baseline crude mix if the GHG emissions from the fuel's crude production and transport steps are subject to control measures such as CCS reduce the crude oil's production and transport carbon intensity to 15.00 grams CO₂e/MJ or less. As a result of the "15-day" modifications, the Executive Officer approval will have to be issued as part of a new rulemaking under the California APA, and parties opposed to the use of CCS will have the opportunity in that rulemaking to explain why it should not be a part of the CO₂e/MJ determination.

None of the values in the carbon intensity Lookup Tables set forth in section 95486(b) reflect consideration of CCS, and no changes to the Lookup Table values can be made without a new rulemaking conducted pursuant to the APA.

E-12. Comment: We ask that you stop and develop rulemaking in compliance with the APA and that can be adopted by the Office of Administrative Law based on completeness. (WSGM, Comment 3059)

Response: As this Final Statement of Reasons amply demonstrates, the Board's approval of the LCFS regulation complied with all applicable APA requirements. And the commenter has not identified any specific procedural deficiencies in the Board's approval of the LCFS regulation. Therefore, there is no reason to stop the rulemaking process for this regulation.

Compliance with CEQA

E-13. Comment: The proposed LCFS does not comply with requirements under the CEQA. The Environmental Impacts Section VII of the ISOR and its corresponding Appendix F inadequately address the potential environmental and environmental justice impacts of this regulation and in many instances postpone analysis until specific projects are proposed. ARB continues to forego the opportunity to have a more exhaustive analysis of impacts and alternatives and ensure a more thorough cumulative impact analysis. The Environmental Impacts analysis fails to inform decision-makers and the public about the significant and cumulative impacts – especially on environmental justice communities, and it fails to provide legally enforceable mitigation measures. (CRPE1, CERA2)

Response: We have considered the commenters' specific CEQA assertions summarized below. For the reasons set forth in the agency responses, we believe ARB has complied with CEQA.

E-14. Comment: While ARB quantifies the potential air pollution from this rule in the Air Quality Impacts section of the ISOR, ARB does not do an analysis of the impacts. The information is available for ARB to analyze the local environmental and environmental justice impacts of the LCFS but the analysis has not been done. ARB could, and should, use the current and probable locations for facilities to look at the localized impacts. This localized analysis is important to determining what communities will be affected the most and whether the LCFS

has a disproportionate impact on low-income or communities of color. (CRPE1)

Response: The commenter focuses on the air pollution impacts from the siting of potentially 25-30 biorefinery facilities in the state, with a substantial number of these located in the San Joaquin Valley. Since the siting decisions will be made by the facility operators subject to approval of local governmental entities that will be subject to CEQA, staff cannot identify any specific sites.

However, in evaluating the potential impacts of new biorefinery facilities, staff chose to conduct a worst-case analysis in which 3 such facilities are collocated and the cumulative adverse air pollution impacts of the 3 facilities are identified. This is discussed in detail in the response to comment E-2.

E-15. Comment: ARB failed to perform a proper analysis of the mitigation measures for the adverse air quality impacts, instead deferring it to the local air districts on a project-by-project basis. While ARB lists a number of potential measures that could mitigate some of the air quality impacts identified, it violates the law by not requiring enforcement of these mitigation measures. (CRPE1)

Examples of ill-defined and/or improperly deferred mitigation measures can be found throughout the Staff Report. See page VII-12 ("ARB staff recommends that the emissions associated with production of low carbon fuels be fully mitigated consistent with local district and CEQA requirements"); page VII-26 ("Any impacts associated with aesthetics, siting and construction of facilities supporting the LCFS would be assessed on a location and project-specific basis"); page VII-27 ("If siting of facilities results in the conversion of agricultural land, this would be subject to the CEQA process and approved by the city or county on a project-by-project basis"); and page VII-31 ("During construction of facilities, traffic impacts can be mitigated through ingress and egress controls to mitigate for congestions, and facility design should include appropriate traffic controls such as turn lanes, traffic lights, and reduced speed zones to ensure safety"). (GE3)

The LCFS should include requirements for state and local review to ensure that the appropriate mitigation measures are taken. (SIERRACLB3)

Response: The potential adverse air quality impacts identified in the Staff Report pertain primarily to emissions from new biorefinery facilities that are expected to be sited in California as a result of the LCFS. Page VII-13 of the Staff Report identifies 6 different strategies that can be used to mitigate emissions from these facilities, including requiring the best available control technologies and requiring the use of the most efficient conversion technologies for the production of low carbon fuels.

In California, local agencies have the legal authority and responsibility to make local land use decisions, such as where individual facilities will be sited. Local agencies have their own regulations and ordinances that project proponents must comply with in order

to obtain the necessary permits. Under state law, the air pollution control and air quality management districts have the primary responsibility for controlling air pollution from nonvehicular sources, including biorefineries. They each administer programs designed to address new stationary sources of air pollution. In most cases these programs are referred to as new source review programs and feature mechanisms to: (1) reduce emission increases up-front through the use of clean technologies, and (2) achieve a no net increase in emissions of nonattainment pollutants or their precursors for all new or modified sources that exceed particular emission thresholds. New biorefineries must also meet CEQA requirements as part of the permitting process. The lead agency must approve an environmental impact report that identifies any significant environmental impacts, identifies feasible alternatives, and incorporates feasible mitigation measures to minimize any identified significant adverse environmental impacts.

Given the primary role of local agencies it is entirely appropriate for ARB to rely on local agencies to carry out their legal responsibilities for siting and permitting decisions, particularly where the specific locations for new biorefinery facilities are unknown at this time.

E-16. Comment: ARB relies on future local land use decision-making processes and project-specific analysis to assess impact and mitigation measures with respect to aesthetics. This is not sufficient, and ARB must do an analysis of the impacts and mitigation measures before adopting the LCFS. ARB is responsible for its own legal compliance and cannot rely on another state agency to mitigate potential impacts. (CRPE1)

Response: Since any impacts on aesthetics are largely dependent on the siting of new biorefinery facilities at locations that are not yet known, it was appropriate to indicate that such impacts would be assessed on a location and project-specific basis.

E-17. Comment: ARB identifies two significant impacts to agricultural resources: the conversion of prime, unique or important farmland and increased cost of food. ARB lists some broad mitigation measures for conversion of farmland, but does not require that such mitigation be employed. ARB also states that conversion of agricultural land would be subject to CEQA and relies on future local decision-making processes. While identifying it as a significant impact, ARB does not address any mitigation for the increased cost of food due to the LCFS. (CRPE1)

Response: The cause of the potential conversion of prime, unique or important farmland would be the siting of new biorefinery facilities. Since the impact on farmland would be highly site-specific, it is appropriate to defer to the local agency CEQA process that would be required prior to the construction of any new facilities.

With respect to the potential loss of food and fiber for fuel and a possible increase in the cost of food, the Staff Report at p. VII-27 notes that this unlikely to occur for prime agricultural land in California because the state's prime agricultural land is too valuable to be used to grow crops for biofuel production. This is addressed in the LCFS through

the requirements to include land use change and indirect effects in determining the carbon intensity of fuel pathways. These pathways will incentivize the production of fuel from non-food feedstocks and from land not used for feed production. As can be seen in the tables in Method 1, the indirect land use change carbon intensity can exceed the pathway carbon intensity for direct effects. ARB also plans to address food for fuel issues as part of larger sustainability concerns, see the response to E-8. Also, these concerns have been addressed in Sections G (Sustainability) and F (Food versus Fuel) in this document.

E-18. Comment: The proposed regulation is not within the scope of ARB's certified regulatory program under CEQA. Therefore, an environmental impact report (EIR) is required. Since there is no EIR, ARB has failed to comply with CEQA and the regulation cannot lawfully be adopted.

In 1978, the Secretary for Resources certified a portion of ARB's regulatory program, exempting those regulations from the CEQA requirements for preparation of EIRs, negative declarations, and initial studies. The certification applied to "the portion of the regulatory program of the State ARB involving the adoption or approval of standards, rules, regulations or plans to be used in the regulatory program for the protection and enhancement of ambient air quality of California." The proposed regulation is not intended to protect or enhance the "ambient air quality of California," but rather is intended to address the issue of global climate change by reducing the emissions of GHG associated with the use of transportation fuels in California. To the extent that the proposed regulation has any effect on "ambient air quality in California," such an effect is clearly incidental to the primary purpose of the proposed regulation.

The Staff Report identifies a variety of "legislative and policy" directives that "support" the LCFS, beginning with the adoption of AB 32 and continuing through the AB 32 Scoping Plan adopted by ARB in December 2008. Importantly, none of these legislative and policy directives existed at the time ARB's regulatory program was certified in 1978. In fact, there were no legislative or policy directives relative to global climate change at that time, as the connection between GHG emissions and global climate change was not generally understood as scientific fact until many years later.

In the 1978 certification decision, the Resources Secretary focused on ARB's authority to establish and achieve certain ambient air quality standards within designated air basins and to protect the public health. Not surprisingly, none of the current policy concerns associated with global climate change – severe droughts, melting ice caps, rising sea levels, increased risk of wild fires and impacts on plant and animal life – are remotely covered by the Resources Secretary's 1978 certification decision. (GE3)

Response: The LCFS rulemaking is covered by the Resources Secretary's 1978 certification regarding ARB regulatory activities.

One of the objectives of AB 32 is to protect and enhance ambient air quality in California, and one of the effects of reducing GHG emissions can be to ameliorate unhealthy levels of ozone in the state's ambient air. AB 32 begins with Legislative findings and declarations. The first pertains to the threats posed by global warming:

HSC section 38501. The Legislature finds and declares all of the following:

(a) Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems. (Emphasis added).

In U.S. EPA's recent action granting California a waiver of preemption under federal Clean Air Act section 209(b) for ARB's "Pavley" GHG emission standards for model year 2009 and later new motor vehicles, Administrator Lisa Jackson stated:

. . . California has made a case that its greenhouse gas standards are linked to amelioration of California's smog problems. Reducing ozone levels in California cities and agricultural areas is expected to become harder with advancing climate change.

* * * *

There is a logical link between the local air pollution problem of ozone and California's desire to reduce GHGs as one way to address the adverse impact that climate change may have on local ozone conditions. Given the clear deference that Congress intended to provide California on the mechanisms it chooses to use to address its air pollution problems, it would be appropriate to consider its GHG standards as designed in part to help address a local air pollution problem. . . ."

74 Fed.Reg. 32744, 32763 (July 8, 2009) (footnote omitted)

The LCFS is one of the major GHG emissions reduction measures under ARB's 2008 Climate Change Scoping Plan, which notes reports that global increases in temperature will lead to increased concentrations and emissions of harmful pollutants in California. (Scoping Plan at ES-10.)

We recognize that AB 32 was enacted 28 years after the 1978 certification decision. However, the commenter does not provide any authority suggesting that the

subsequent enactment of new Legislative mandates in and of itself makes a prior CEQA functional equivalent certification inapplicable to the adoption of regulations implementing the new mandates. Given the Legislative finding in HSC section 38501(a) and the potential effect that global warming has on ozone concentrations in California's ambient air, the LCFS regulation is well within the 1978 CEQA certification.

E-19. Comment: The Staff Report acknowledges or indicates that the proposed regulation may have adverse effects in the areas of energy consumption, air quality, water quality, biological resources, and hazardous materials. Nonetheless, the Staff Report fails to evaluate any alternative to the proposed regulation that may avoid or lessen any of the potential adverse environmental impacts identified in that document. For example, the Staff Report fails to evaluate an alternative to the proposed regulation that would establish a "level playing field" by eliminating the indirect land use "penalty" for crop-based ethanol fuels. By eliminating the "advantage" given to traditional petroleum-based fuels under the proposed regulations, such an alternative could lessen the potential impacts associated with the continued use of such fuels. Such an alternative could also eliminate the need for some of the estimated 30 new biofuel facilities that are assumed in the Staff Report, thereby further reducing the potential impacts of the proposed regulation. (GE3)

Response: The land use change (LUC) element that is part of the carbon intensity determination for certain crop-based biofuels is essential to ensuring the full GHG emissions benefits of the LCFS program. The basis and need for the LUC element is set forth in Chapter IV of the Staff Report and in the responses in this FSOR to the comments opposing its inclusion. These discussions demonstrate that omission of the land use change provisions could result in the elimination of all GHG emissions reductions and negate the essential objective of the LCFS. Therefore a specific discussion of the no land-use change "alternative" was not required in the environmental impacts chapter of the Staff Report.

E-20. Comment: Our comments raise significant environmental issues relative to the proposed regulation. Therefore, pursuant to applicable regulations, ARB staff must summarize and respond to the comments either orally or in a supplemental written report. 17 CCR § 60007. Additionally, prior to taking final action on the proposed regulation, ARB must approve a written response to each environmental issue raised in this letter. (GE3)

Response: The comments raising significant environmental issues submitted by Growth Energy and others have been summarized in this FSOR. In the Executive Order adopting the regulations, ARB has approved the written responses to these comments.

Multimedia Evaluation

E-21. Comment: Given the considerable economic and public health risks of switching

and mixing fuel blends, with often unknown or controversial results in localized communities, and the need for "compatibility" of engine, vehicle, and infrastructure needs, a full multimedia analysis is and should be required to assess potential environmental and public health harms and help guide regulated entities when making investment decisions. Reducing carbon-intensity by 10 percent is a "specification" for the fuel, where the intent of SB 529 was passed in direct response to MBTE contamination concerns, and such concerns about potential damage from fuel composition are controlling pursuant to HSC section 43830.8. (CERA2)

Comment: The LCFS is a fuel reformulation and is subject to a multimedia review. CARB avoids regulatory requirements by avoiding the terms "reformulation" and "fuel specification." California HSC section 43830.8(a) prohibits CARB from adopting a regulation that establishes a specification for motor vehicle fuel unless the regulation undergoes the multimedia review process specified in the statute. The multimedia requirement does not apply if the regulation does not establish a motor-vehicle fuel specification. Clearly, a carbon intensity standard is a fuel specification as are limits on aromatics and sulfur. The semantics assessment in the Staff Report sets a standard for carbon intensity and, because it is a motor vehicle fuel specification, triggers a multimedia evaluation. (IWLA)

Response: Pages V-26 to V-33 of the Staff Report contain a comprehensive analysis of whether adoption of the LCFS regulation "establishes a specification for motor vehicle fuel," therefore triggering the need for an immediate multimedia evaluation by the California Environmental Policy Council pursuant to HSC section 43830.8. After considering the public comments, we continue to believe that the Legislature intended the term "specification" to refer to an ARB mandate on a motor vehicle fuel's permissible composition rather than to a requirement like the LCFS's carbon intensity standards that pertain primarily to how the fuel is produced and distributed.

It is uncontroverted that SB 529 enacted HSC section 43830.8 in 1999 in direct response to MTBE contamination concerns. In the late 1990's, most California gasoline contained approximately 11 percent by volume MTBE, in large part because of the minimum oxygen content requirements in the California Phase 2 RFG (CaRFG2) and federal RFG regulations, and to some extent the CaRFG2 specifications for maximum T50 and T90 distillation temperatures. MTBE is an ether that contains 18.2 percent by weight oxygen; when combined with gasoline at 11 percent by volume the blend met the wintertime minimum oxygen content standard of 1.8 percent by weight in the CaRFG2 regulations and the year-round minimum oxygen content standard of 2.0 percent by weight in the federal RFG regulations. Adding the MTBE also depressed the distillation temperatures of the gasoline blend, helping to meet the T50 and T90 standards. Thus, to meet the gasoline specifications in the CaRFG and federal RFG regulations, refiners generally produced gasoline composed of 2 percent by weight oxygen coming from 11 percent by volume MTBE.

After MTBE started to be used in most California gasoline, its presence was detected in various groundwater samples, including public drinking water supplies in South Lake Tahoe, Santa Monica, Los Angeles, San Francisco, and other locations. Since MTBE is highly soluble in water, it will transfer to groundwater faster, farther, and more easily than other gasoline constituents such as benzene when gasoline leaks from underground storage tanks and pipelines. Along with toxicological concerns, very low levels of MTBE in drinking water can be tasted and smelled by susceptible individuals with the taste characterized as solvent-like, bitter, and objectionable.

The Legislature's decision to make the multimedia evaluation requirements applicable to any ARB "regulation that establishes a specification for motor vehicle fuel" resulted from concern that the CaRFG2 specification for minimum oxygen content led to the production of California gasoline composed of 11 percent by volume MTBE. In contrast, the motor vehicle fuels requirement imposed by the LCFS compares the carbon intensity standards in the regulation to the carbon intensity of particular fuels – representing all of the direct GHG emissions associated with producing, transporting and using the fuel, along with the GHG emissions associated with land use for some crop-based biofuels. Compliance with the carbon intensity standard depends much less on the composition of the fuel than on how the fuel is produced and distributed. In fact, different fuels with identical compositions can have significantly different carbon intensities because of production and distribution differences.

E-22. Comment: Parties are moving ahead with plants that would produce ethanol for use as a transportation fuel from feedstocks such as garbage. Burning trash as fuel threatens multiple environmental and environmental justice harms, including increasing toxic and criteria pollutants and disproportionately impacting low-income communities located near the facilities. The ARB could save at least \$100 million in wasted investments if staff conducted a multimedia analysis from the outset, versus waiting an indefinite amount of time until after the build-up of infrastructure and capital to determine that burning trash violates several environmental laws. Protection of public health and the environment was the overriding objective of SB 529, and under the statutory definition of "multimedia evaluation" in HSC section 43830.8(b) the assessment is to include consideration of significant adverse health or environmental impacts from the production of the motor vehicle fuel that may be used to meet the ARB's motor vehicle fuel specifications. (CERA2)

Response: If the construction and operation of a trash burning facility would violate several environmental laws, those laws can be enforced irrespective of any multimedia evaluation under HSC section 43830.8.

We agree that the objective of SB 529 was to protect public health and the environment. We also agree that when a multimedia evaluation of a newly established motor vehicle fuel specification is conducted, the health and environmental impacts associated with the production of the fuel that may be used to meet the ARB fuel specification are to be considered. But this does not mean that any new ARB requirement that may affect the

way motor vehicle fuel is produced is necessarily a fuels “specification” triggering a multimedia review – even though the requirement does not impose a mandate on the composition of the fuel.

E-23. Comment: Given that there are great risks in burning trash and other feedstock sources, the overriding considerations of public health and safety that was the legislature's intent in passing SB 529, trumps ARB staff's attempt to defer their way out of the requirement by arguing semantics.

The authority that ARB staff gives to justify its narrowed interpretation of “specification” cites one of many possible dictionary definitions and a statute last amended nine years before SB 529 took effect. ARB staff's narrowed definition based upon an implied “subset” interpretation of an outdated statute leads to a contrary conclusion than ARB staff asserts. The ISOR reasons that in the HSC section 43018 “context, the Legislature seems to use the term ‘specification’ as a subset of motor vehicle ‘standards,’ ‘regulations,’ and ‘measures.’” Thus, one can reasonably presume that, in the context of motor vehicle fuels, the Legislature intended the term ‘specification’ to be an ARB mandate on a vehicular fuel's permissible composition, rather than on the production process for the fuel.” However, the LCFS is a mandate on a vehicular fuel's permissible composition of carbon-intensity, a tangible substance that gets burned along with other co-pollutants and emitted into the atmosphere, specified to be reduced 10 percent by 2020. Whereas the LCFS does not propose to require any specified “production process for the fuel” such as requiring wet versus dry mill facilities in the production of corn-ethanol. (CERA2)

Response: HSC section 43018, which contains the provisions referring more broadly to motor vehicle fuel “standards and regulations” and more narrowly to a “specification of vehicular fuel composition” – is hardly an outdated statute. Rather it remains the primary statutory authority for ARB to adopt motor vehicle fuel standards and regulations to attain ambient air quality standards. The Legislature's choice of the phrase “specification of vehicular fuel composition” is significant.

Moreover, we cannot agree that the LCFS mandates “a vehicular fuel's permissible composition of carbon intensity, a tangible substance that gets burned along with other co-pollutants and emitted into the air.” Carbon intensity is not a tangible substance. For instance, a regulated party may be deciding which of three batches of ethanol to use – Midwest corn ethanol from a wet mill facility, Midwest corn ethanol from a dry mill facility and Brazilian sugarcane ethanol using average production processes. The chemical composition of the three batches of ethanol could well be essentially identical, and the GHG emissions resulting from combustion of the ethanol in the vehicle engine could also be essentially identical. Yet there could be significantly different carbon intensities attributed to the three batches considering solely the production processes and emissions from distribution. The LCFS does not require any particular production process for the fuel such as requiring wet versus dry mill facilities in the production of corn ethanol. But the use of a wet mill versus a dry mill will directly affect the ultimate

carbon intensity of the ethanol irrespective of the composition of the ethanol.

E-24. Comment: The language in HSC section 43830.8(b) itself better informs legislative intent on if the multimedia analysis requirement is triggered. The multimedia evaluation "means" to identify and evaluate adverse impacts from the "production, use, or disposal of the motor vehicle fuel that may be used to meet the state board's motor vehicle fuel specifications." Here the statute clarifies a "fuel that *may* be used to *meet*" the state board's motor vehicle specifications, inferring that multiple fuels could be used to meet or fulfill a given motor vehicle specification. This is the case under the LCFS where multiple fuels could be used to meet the 10 percent carbon-intensity reduction specification. Whereas, if the legislature intended ARB staff's interpretation of "fuel specifications" as being specific to a particular fuel type, the stated meaning of "multimedia evaluation" would have read the opposite direction, such that fuel specifications are contained or limited by the fuel type. (CERA2)

Response: Section 43830.8(b)'s reference to "fuel that may be used to meet" ARB fuels specifications does not mean the Legislature must not have intended "specifications" to refer to the composition of the fuel. If ARB adopted a minimum oxygen content specification, there could be more than one oxygenate that a refiner may choose to use to add the oxygen, e.g., MTBE or ethanol or ETBE. The multimedia evaluation is not necessarily limited to one additive, or one kind of processing, to produce a fuel that meets specifications for the composition of a motor vehicle fuel.

E-25. Comment: Furthermore, ARB staff's suggested approach to conduct multimedia evaluations on an ad hoc and per fuel type basis will ignore the cumulative effects of the overall LCFS program, and could potentially allow a fuel type to avoid a multimedia evaluation entirely when ARB staff claim they are exempt from the "pre-sale prohibition." The suggested "grandfathering" of fuel types that have not had their "specifications" amended since SB 529 was enacted pursuant to subsection §43830.8(h) confuses the statute's call in subsection (a) for the California Environmental Policy Council to review the proposed LCFS "regulation that establishes a specification for motor vehicle fuel." When prior fuel specifications were approved before July, 2000, they were under different regulations. Whereas the LCFS regulation carries along with it numerous new legal requirements under AB 32, new scientific methodologies and uncertainties as described elsewhere in these comments, and a wide range of environmental impacts never considered a decade ago. Thus, ARB staff cannot "grandfather" fuels to be included in the LCFS based upon prior evaluations of other regulations. Meanwhile, there is no basis to exempt "[t]hose fuels for which there are no existing ARB specifications but are permitted for sale in California pursuant to regulations promulgated by the Division of Measurement Standards – this includes biodiesel and renewable diesel." (CERA2)

Response: Again, this comment is premised on the belief that the carbon intensity standards are a "specification for motor vehicle fuel" and therefore trigger a requirement

for a multimedia evaluation under HSC section 43830.8(h). As discussed in previous responses, we believe this is not the case because the LCFS does not establish specifications for motor vehicle fuel composition.

Apart from the express mandate of HSC section 43830.8, we recognize the strong interest in the benefits of a multimedia review for biodiesel and renewable diesel, since there are no applicable ARB specifications and these fuels are expected to be increasingly used to comply with the carbon intensity standard for diesel fuel and diesel fuel substitutes. ARB has accordingly initiated a multimedia review by the Environmental Policy Council. This was also initiated in anticipation of the ARB considering the establishment of specification for bio and renewable diesel. Although ARB approval of such specifications will not be complete by the time the LCFS regulation is adopted and submitted to the Office of Administrative Law, we expect it will be completed by December 2010. If the evaluation identifies any significant adverse impact on public health or the environment, ARB is committed to take appropriate action.

E-26. Comment: The ISOR states that "conducting such [a multimedia] evaluation for the overall rule would make it practically very difficult, if not impossible, to conduct such an evaluation. . ." Using ARB's rationale, just because an individual may find it difficult to meet a legal requirement, e.g., requiring passing a driver's test, does that give the person the right to just ignore the law? Or is the difficulty in meeting the requirement an indicator that perhaps the law is meant to protect against the very activity that the person wishes to engage in? The multimedia evaluation requirement is meant to protect against future harms from burning random substances as fuel, the very situation that the LCFS will create. ARB staff asserts that given the difficulty of conducting a multimedia analysis "the best that ARB staff can provide at this time is the 'functional equivalent' of a multimedia evaluation. "However, HSC section 43830.8 does not allow for a 'functional equivalent' to implement the "spirit" of the statute "to the extent feasible" that staff currently proposes. HSC section 43830.8(i) unequivocally states "the State Board may adopt a regulation that establishes a specification for motor vehicle fuel without the proposed regulation being subject to a multimedia evaluation if the [California Environmental Policy Council], following an initial evaluation of the proposed regulation, conclusively determines that the regulation will not have any significant adverse impact on public health or the environment." The Council has not made such a determination as required by the statute, and therefore, the ARB Board should not adopt the LCFS at this time. (CERA2)

Response: ARB is not ignoring HSC section 43830.8; rather this is an issue of statutory construction. Again, we have explained the basis of our interpretation in the responses to preceding comments.

E-27. Comment: Although the submitted proposal is incomplete, at its core is a fuel transformation that impacts the state's supply of diesel fuel specifications. CARB details its expectation that, as new, lower carbon intensity fuels are developed, it

will need to establish fuel specifications to allow the sale of such fuels in California. CARB recognizes that the need to conduct multimedia evaluations for the specific fuels and has started a multimedia evaluation for biodiesel and renewable diesel fuel. The new fuel specifications are planned in a future rulemaking.

Moving forward without completing the multimedia evaluations on biodiesel and renewable diesel violates the plain language of the statute and must be completed before the regulation is adopted pursuant to HSC section 43830.8 – a law designed protect the public and end users from this very situation. (IWLA)

Response: As we have explained in the responses to previous comments, we do not believe that HSC section 43830 requires a multimedia evaluation of the LCFS regulation and its carbon intensity standards because they do not establish specifications for the composition of motor vehicle fuel. Nevertheless, we are moving ahead on a multimedia evaluation of biodiesel and renewable diesel fuel since there are presently no ARB specifications for these fuels, and we expect they will be used in compliance with the LCFS regulation.

E-28. Comment: CARB has determined that the proposal, by itself, does not establish motor-vehicle fuel specifications. The concept of setting a performance standard that is prescriptive for carbon intensity (CI) makes it a standard. Companies with compliance obligations must meet the CI standard or face enforcement penalties. CARB states they “expect that as new, lower-carbon intensity fuels are developed over time, ARB may need to establish fuel specifications to allow the sale of such fuels in California.”

Government Code section 11342.570 provides the definition of a performance standard and prescriptive standard. "Performance standard" means a regulation that describes an objective with the criteria stated for achieving the objective. The CI standards are set by CARB and decline over time, creating a declining prescriptive standard, not a performance standard. This prescriptive standard defines a specific action that has a quantifiable limit for CI in fuels.

Government Code section 11342.590 better assesses the objective of this rulemaking as a "prescriptive standard" defined as “a regulation that specifies the sole means of compliance with a performance standard by specific actions, measurements, or other quantifiable means.” The only way to reduce the CI in diesel fuel is to add renewable fuel or biofuel to the existing refined product. Doing so does not differ from adding cetane to diesel fuel to reformulate it or to make CARB diesel. The only difference is that the recipe for the LCFS requires a renewable additive. (IWLA)

Response: As discussed in the responses to previous comments, the key characteristic of the carbon intensity requirements is that one cannot determine the carbon intensity level of a fuel by analyzing the composition of the fuel. Fuels or fuel

components that have identical physical and chemical properties can have different carbon intensities depending on how the fuel or fuel component is made, distributed and used. This is why the LCFS regulation does not establish a specification for motor vehicle fuel. In any event, the carbon intensity is more akin to a performance standard than a prescriptive standard. The regulation does not dictate a sole means of compliance with the average carbon intensity requirements, and compliance cannot be determined by simply sampling and testing transportation fuels. Moreover, there is one average carbon intensity level that applies to all of the various transportation fuels for which a regulated party is responsible in a year, with the option of acquiring credits or using banked credits.

E-29. Comment: CARB plans to assess penalties and mete out other remedies for violations of regulations adopted pursuant to AB 32, found in HSC section 38580. If this rulemaking is not a fuel reformulation and on that basis is not subject to a required multimedia review, how can fines be levied against obligated parties? (IWLA)

Response: HSC section 38580(b)(1) provides that “Any violation of any rule, regulation, order, emission limitation, emissions reduction measure, or other measure” adopted the Board pursuant to AB 32 is a violation subject to the penalties applicable to ARB’s other regulations. There is no reference to “fuel reformulations” and no exception for AB 32 regulations that are not fuel reformulations. The LCFS regulation establishes specific prohibitions applicable to regulated parties, and violations of those prohibitions are subject to HSC section 38580.

E-30. Comment: Further, HSC section 43029 provides additional penalties designed to eliminate the economic benefits gained from a regulated party’s noncompliance. CARB cannot have it both ways: either CARB is effecting a fuel reformulation with an enforcement mechanism that is subject to a required multimedia review or there is no fuel reformulation and, if so, no compliance requirement. (IWLA)

Response: HSC section 43029 identifies penalties applicable to violations of ARB’s non-AB 32 regulations pertaining to “fuel requirements or standards,” “gasoline requirements” and “diesel fuel requirements.” HSC section 35830(b)(1) makes these penalties applicable to violations of AB 32 regulations as well. These penalties will accordingly be applicable to violations of prohibitions in the LCFS regulation. Nothing in HSC section 43029 affects the question whether the LCFS regulation establishes a specification for motor vehicle fuel that is subject to the HSC section 43830.8 requirement for a multimedia review.

E-31. Comment: ARB should provide its legal analysis of the applicability of HSC section 43830.8 to ARB’s adoption of the LCFS regulation. This could avoid the question of how staff’s proposed “functionally equivalent” LCFS multimedia assessment would work. For example, will ARB be submitting it to the California Environmental Policy Council for their review? Why perform “real” multimedia

assessments later if ARB is going to perform a “functionally equivalent” multimedia assessment upfront now? In ARB’s “functionally equivalent” LCFS multimedia assessment:

- a. How will ARB address emissions of all air pollutants, including ozone forming compounds, particulate matter, and toxic air contaminants as well as emissions of greenhouse gases resulting from each pathway?
- b. How will ARB address potential contamination of surface water, groundwater, and soil resulting from each pathway?
- c. How will ARB address disposal or use of the byproducts and waste materials from the production of the fuel resulting from each pathway?

Why not address these multimedia issues as much as possible up front to facilitate the implementation of the LCFS, lower its cost and avoid mistakes? ARB staff’s approach of conducting a functionally equivalent assessment for the LCFS rulemaking to implement the “spirit” of HSC §43830.8 fails to address upfront the adverse environmental impacts that are associated with producing fuels that can meet the carbon intensity requirements under the LCFS. Such an approach also ignores the possibility that ARB may never conduct a multimedia evaluation of all the LCFS fuel pathways. It completely ignores the possible interaction between alternative pathways that might produce cumulative impacts. (WSPA1)

Comment: ARB is legally required to conduct a multimedia evaluation. Given the considerable economic and public health risks of switching and mixing fuel blends, with often unknown or controversial results in localized communities, and the need for “compatibility” of engine, vehicle, and infrastructure needs, a full multimedia analysis is and should be required to assess potential environmental and public health harms and help guide regulated entities when making investment decisions. Reducing carbon-intensity by 10 percent is a “specification” for the fuel, where the intent of SB 52 was passed in direct response to MTBE contamination concerns and such concerns about potential damage from fuel composition are controlling pursuant to HSC section 43830.8. (CERA1, CERA2)

Comment: CARB is misusing the term “performance standard” to avoid the required multimedia evaluation required by state law. (IWLA).

Comment: Carbon intensity is a criterion or “specification” to which motor vehicle fuels must comply. The LCFS will change specifications of California reformulated gasoline and diesel and will require fuel additives to be added or taken out and new fuels to be used statewide. ARB is not permitted to avoid the statutory requirements under HSC §43830.8 to perform a multimedia evaluation by simply labeling the LCFS a “standard” as opposed to a “specification.” Any attempt to do so is contrary to the legislative mandate in AB 32 that ARB must comply with existing fuel regulations in satisfying its obligations under AB 32.

HSC §38598(b) (“Nothing in this division shall relieve any state entity of its legal obligations to comply with existing law or regulations.”). (WSPA1)

Response: The Board’s legal analysis of the applicability of HSC §43830.8 to ARB’s adoption of the LCFS regulation is already set forth in detail in the Staff Report, pages V-26 through V-33. Based on that legal analysis and technical rationale, the Board made a finding in Resolution 09-31 that adoption of the LCFS regulation does not, in itself, constitute establishment of a motor-vehicle fuel specification, and therefore, does not trigger the multimedia evaluation requirement under HSC §43830.8(a). Had the LCFS regulation triggered the multimedia evaluation requirements, the Board staff would have been required to submit a summary of its multimedia evaluation and the results of a peer review (conducted in accordance with HSC §57004) to the California Environmental Policy Council (CEPC) for its review and comments (HSC §43830.8(d)).

However, because the Board found that the LCFS regulation does not trigger the statutory requirements for a multimedia evaluation in the first place, it follows that the requirement to submit a summary and subject the functionally equivalent assessment to a CEPC review is also not triggered. It also follows that, because the Board determined that the LCFS does not trigger the HSC §43830.8 requirements, there is no conflict with HSC §38598(b). Therefore, the Board’s functionally-equivalent multimedia assessment meets the requirements of State law and is not required to be submitted to the CEPC.⁷

Notwithstanding the commenter’s characterization of the functionally equivalent analysis in the ISOR, the Board believes it has adequately addressed the multimedia issues as much as possible up front. With regard to why the Board conducted a functionally equivalent assessment upfront if the staff is planning to conduct “real” multimedia evaluations later, the answer to this is simple and set forth in the Staff Report on page V-32. In addition to the legal basis for why the HSC §43830.8 requirements are not triggered, there is a practical limit to the extent a multimedia evaluation can be performed on a performance-based regulation like the LCFS that doesn’t establish a fuel specification.

Simply put, a full multimedia evaluation is best conducted when a fuel specification is established because there would presumably be much more specific information available that shows how regulated parties are expected to make their products meet such a specification. By contrast, the LCFS can be met by any number of means allowed under the regulation. This includes varying the feedstocks used to make a pool of fuel, varying the sales of fuels, purchase or sale of LCFS credits, and any combination of these and other allowable methods. Thus, because of the number of possible ways to comply with the LCFS and because not all the ways allowed require reformulation of a fuel, it would be impractical to attempt a comprehensive and accurate

⁷ It should be noted that the LCFS regulation, along with the Board’s legal and technical rationale for the functionally equivalent assessment, was submitted to the peer review process required under H&S §57004. Pursuant to that process, the peer reviewer who commented on the Board’s rationale found that the Staff Report appears to address the multimedia requirements properly. Prof. Marr Peer Review at 7, http://www.arb.ca.gov/fuels/lcfs/peerreview/041409lcfs_marr.pdf.

multimedia evaluation on the LCFS regulation that would meet the requirements of HSC §43830.8.

Further, such an evaluation, even if conducted, would be incomplete because a facility built to produce fuel in response to the LCFS may have impacts on air, water, soil and other environmental impacts that are specific to that site (e.g., impacts on soil surrounding a facility depend on the properties of the soil on which the facility is built, which can vary from location to location). However, it would be impractical to attempt to quantify up front these impacts at the local and regional level for every possible type of facility in every type of location in California because of these site-specific considerations. Because of this, the localized and regional impacts from construction and operation of biorefineries and other facilities built in response to the LCFS can best be identified at the local and regional level when a fuel specification is proposed.

Based on its legal and technical rationale, the Board believes the appropriate analysis for the adoption of the LCFS is to conduct a functionally equivalent assessment of the environmental and public health impacts to the extent possible. This was done in extensive detail in the Staff Report, pages VII-1 through VII-37. As noted on pages V-32 through V-33 in the ISOR, the Board determined that the appropriate point at which to conduct comprehensive multimedia evaluations pursuant to HSC §43830.8 is when post-LCFS implementation regulations are promulgated by the Board. For example, ARB staff plans to propose a new fuel specification for biodiesel in 2010. Because Board adoption of that proposal would establish a new motor vehicle fuel specification, a multimedia evaluation will need to be completed for that proposed rulemaking and subjected to the process involving peer review and review by the CEPC as noted above.

With regard to the specific impacts identified in a, b, and c above, the ISOR, on pages VII-1 through VII-36, already contains an extensive discussion of how the Board identified and quantified these impacts to the extent possible. In Resolution 09-31, the Board found that, overall, the approved regulation is expected to achieve significant reductions in greenhouse gas emissions. In addition, the Board found that the regulation is expected to result in no significant additional adverse impacts to California's statewide air quality due to emissions of criteria and toxic pollutants; however, some small but potentially significant adverse impacts on a localized or regional basis from the construction and operation of biorefineries may occur, as noted in the Resolution.

In general, the Board found that any direct emissions from new biorefineries are likely to be mitigated as part of the CEQA process and local air district permitting actions. Accordingly, no significant adverse impacts on a regional basis are expected as a result of direct emissions from such facilities. While some increases in localized emissions could occur, the Board's analysis has not identified any significant criteria or toxic air pollutant impacts from direct biorefinery emissions that cannot be mitigated through local actions (e.g., through requirements to apply best available control technology).

The Board also found that some new California biorefineries could use significant amounts of water that could result in significant impacts. However, because all new facilities would need to meet CEQA and agency permitting requirements, including requirements of the California Regional Water Quality Control Boards, the final determination of impacts on water would need to be made on a site-specific basis.

Except for the emissions impacts and water use impacts described in Resolution 09-31 and noted above, the Board found there are no significant adverse environmental impacts that will occur from the LCFS regulation.

With regard to the comments that CARB is misusing the term “performance standard” and that the LCFS mandates a 10 percent reduction in carbon intensity and is therefore, a “specification,” we disagree because the Board found that the LCFS is a performance standard that does not constitute a “specification,” as noted above. And with regard to the comment on SB 52, we note that the plain language of HSC §43830.8 specifically ties the requirement for a multimedia evaluation to ARB’s establishment of a motor vehicle fuel “specification” had the Legislature intended for the multimedia evaluation to be required for all motor vehicle fuel regulations, it could have easily used the broader terms “regulation,” “measure” or a similar term. But, as pointed out in the Staff Report on pages V-26 through V-33, the Board determined that the Legislature’s specific use of the term “specification” reflects a legislative intent to narrow the focus of the requirements only to those regulations that actually establish prescriptive fuel specifications.

E-32. Comment: We recommend ARB conduct a complete multimedia environmental evaluation, pursuant to the requirements of HSC section 43830.8, for the following:

- a. the LCFS regulation itself (ACE, CERA2, IWLA)
- b. the diesel carbon intensity specification in the LCFS (AB32IMPG, IWLA)
- c. biodiesel (AB32IMPG, CCOC, IWLA);
- d. hydrogen and natural gas and other fuels that could comply with the LCFS (WSPA1)
- e. the impacts on all media, including air, water, and soil, from the release of GHGs under the LCFS regulation, because the LCFS is primarily designed to reduce GHG emissions, and HSC section 43830.8 requires all multimedia evaluations to address emissions of GHGs for any newly proposed fuel regulation. (ACE)

Response: For comments a through d, we disagree. As discussed in the response for Comment E-31, the Board found in Resolution 09-31 that adoption of the LCFS regulation does not, in itself, constitute establishment of a motor-vehicle fuel specification and therefore, does not trigger the multimedia evaluation requirement under HSC section 43830.8. The reasons for this finding were set forth in the Staff Report, pages V-26 through V-33.

To summarize, the LCFS regulation accounts for and governs the collective GHG emissions released during the lifecycle of a regulated transportation fuel (i.e., during the growth/extraction, production, distribution, transport, and use of the fuel) (*Id.* at ES-1 through ES-2, V-27). The LCFS requires regulated parties (generally producers and importers) to account for those lifecycle emissions on a “carbon-intensity” basis for its entire fuel pool as a whole; the carbon-intensity for all fuels that a regulated party is responsible for is subject to a declining carbon-intensity curve, resulting in an overall reduction in carbon-intensity for the entire transportation fuel pool in California of 10 percent by 2020.

The Board found that the LCFS’ regulatory structure does not establish a motor vehicle fuel “specification” because a specification is prescriptive in nature (e.g., “a fuel shall contain no more than 10 percent of Component A...,” or “no fuel shall have an API gravity that is more than Y...”)(*Id.* at V-28 through V-30). By contrast, the LCFS is structured as a “performance standard” in that it imposes no such physical or chemical property that can be measured in a laboratory on a specific volume of a given fuel. Instead, the LCFS requires regulated parties to simply identify and add up all the GHG emissions during a fuel’s lifecycle, repeat this for all of the fuels in its transportation fuel pool in California, and then compare the resulting total carbon intensity with the carbon-intensity curve for that compliance year. If a shortfall occurs, the regulated party is required to reconcile this shortfall through purchase of sufficient credits or potentially be subject to a violation and penalties (*Id.* at V-30 through V-31).

Based on the reasons set forth in the Staff Report, the Board believes it reasonably determined that the LCFS regulation does not, by itself, establish motor vehicle fuel specifications that trigger the multimedia evaluation requirements under HSC section 43830.8. With that said, the Board also found that subsequent rulemakings to implement the LCFS may establish vehicular fuel specifications (e.g., for biodiesel), in which case a multimedia evaluation would be required (*Id.* at V-32 through V-33). The LCFS regulation sets forth provisions that explicitly recognize this requirement (17 CCR §95487).

With regard to diesel fuel, no separate multimedia evaluation is required because such a multimedia evaluation was conducted the last time the diesel fuel specifications were amended in July 2003. See Air Resources Board, “Recommendation on Need for a Multimedia Evaluation of Amendments to the California Diesel Fuel Regulations: Report to the California Environmental Policy Council,” www.arb.ca.gov/fuels/multimedia/043004rpt.pdf, last visited on Aug. 17, 2009. The LCFS regulation does not, by itself, modify or otherwise affect existing California fuel regulations in any way (ISOR *op cit.* at V-31 through V-32). And, as noted above, the LCFS does not, by itself, establish any new motor vehicle fuel specifications, including any new specifications for motor vehicle diesel fuel. Thus, the multimedia evaluation conducted for the existing diesel fuel regulation remains valid, and no additional evaluation is required under the LCFS.

With regard to comment e, we disagree. In approving the LCFS, the Board found that the regulation is expected to significantly reduce emissions of GHGs, such as CO₂, methane, nitrous oxide, and other GHG contributors from the use of transportation fuels subject to the LCFS (by about 16 and 23 million metric tons of carbon dioxide by 2020, accounting for combustion of the fuel only and for the full fuel lifecycle, respectively) (Resolution 09-31 at 9). Further, the Board found that, in addition to identifying the potential impacts of the LCFS on air quality, the ISOR contains an assessment of other potential environmental impacts that might result from the implementation of the LCFS, including, among others, the potential impacts on water quality and water use; agricultural resources; biological resources; hazardous waste and hazardous materials; solid waste; and transportation and other traffic (*Id.* at 13). The Board's analysis of the LCFS impacts on media including air, water, and soil, from the release of GHGs are set forth in detail in the Volumes I and II of the ISOR (VII-1 through VII-36 and Appendix F, respectively).

E-33. Comment: There should be no lowering of air quality standards for emissions from burning methane in engines, especially in areas such as the San Joaquin Valley. The dairies are having a problem getting the methane clean enough for burning under current emission standards. There needs to be a clear statement in the LCFS that air emission standards will not be lowered for biomethane or any other fuel or gas manufactured and/or used in the State. (AIR)

Response: We agree that there should be no lowering of air quality standards, but we disagree that a clear statement as suggested is needed in the LCFS. The LCFS regulation already contains a savings clause (section 95480.1(e)), which specifically provides that the LCFS does not amend, repeal, modify or change any other applicable State or federal requirements, including the existing California fuels regulations. Among the existing State fuels regulation is the regulation governing specifications for compressed natural gas (CNG) used in motor vehicle fuel (13 CCR §2292.5).

Thus, the LCFS does nothing to lower the existing air quality standards for burning methane (the principal ingredient in motor vehicle CNG and LNG). Any natural gas that is used to meet the LCFS requirements would also need to meet the ARB specifications for such CNG. Because of the savings clause, there is no need to add the statement requested by the commenter. But even without the savings clause, State law would require regulated parties to meet all applicable State laws and regulations, including both the LCFS (once it is in force) and existing regulations, such as 13 CCR §2292.5.

E-34. Comment: We are unsure of how CARB will ensure that biodiesel use does not increase NO_x emissions; however, we note that the use of fuel additives to address this issue will further increase the cost of biodiesel and will require significant testing to ensure that it will not adversely impact engine durability or the long term efficacy of emissions control equipment. (ATA 193)

Response: ARB will ensure that biodiesel fuel use does not increase NO_x emissions significantly by promulgating a new motor vehicle fuel specification for biodiesel. Such

a specification is tentatively planned to be proposed for the Board's consideration in mid-2010. As noted in the response to E-33 above, the LCFS does not modify in any way any other applicable State or federal requirements. The ARB has not yet adopted any motor vehicle fuel specifications for biodiesel. However, biodiesel is subject to regulations promulgated by the California Department of Food and Agriculture, Division of Measurement Standards (DMS) (ISOR at II-11 through II-12). Thus, NOx emissions are not expected to increase under the LCFS relative to the current level of NOx control under DMS regulations.

As part of the aforementioned ARB rulemaking to establish biodiesel specifications, staff will evaluate the feasibility and costs of using fuel additives with biodiesel, the associated testing, and whether there might be engine durability or control equipment issues. The Board will consider these factors and others when it considers the biodiesel specifications regulation for adoption, now tentatively scheduled for 2010.

E-35. Comment: Burning trash to convert it into an alcohol-based fuel, as Blue Fire Ethanol Fuels plans to do and the LCFS allows, threatens multiple environmental and environmental justice harms, including toxic and criteria pollutants and disproportionately impacting low-income communities located near the facilities. The ARB could save at least \$100 million in wasted investments, as evidenced in the L.A. Times article, if staff conducted a multimedia analysis from the outset, versus waiting an indefinite amount of time until after the build-up of infrastructure and capital to determine that burning trash violates several environmental laws. (CERA2).

The ARB should conduct multimedia evaluations now for all of the likely LCFS-compliant fuels in order to encourage investment in and development of a full and competitive range of such fuels. The deadline for implementing early action measures under AB 32, such as the LCFS, is fast approaching, and any delay in the development of LCFS-compliant fuels will further add to the many challenges and risks of implementing AB 32 successfully. (WSPA1)

Response: As noted in the response to Comment E-31, the Board found in Resolution 09-31 that new facilities in California built to produce transportation fuel for the LCFS would need to meet CEQA and local agency permitting requirements, and the final determination of impacts on air, soil, water and other environmental impacts would need to be made on a site-specific basis. It follows that facilities built to convert trash into transportation fuel would have to undergo the CEQA and permitting process in order to be constructed and to operate legally. It should be noted that the Board, in recognition of environmental justice concerns, directed ARB staff in Resolution 09-31 to:

“work with local air districts, regulated parties, environmental advocates, public health experts and other stakeholders to develop a ‘best practices’ guidance document for use by siting authorities when they are considering the siting of biofuel and other fuel production facilities in California to

assess and mitigate the air quality impacts of these facilities and to present the guidance document to the Board by December 2009.”

With regard to the comments that attempt to link multimedia evaluations with investments in LCFS fuels, we note that ARB’s role in promulgating the LCFS regulation is not to pick winners or losers among investors in the transportation fuels sector. The LCFS simply identifies, based on the best available science, the lifecycle carbon intensity of transportation fuels in California and requires a 10 percent overall reduction in the carbon intensity of the overall fuel pool by 2020. Neither ARB nor the LCFS regulation serves in the role of investment advisor; investors must conduct their own due diligence in determining the worth of an investment, and no investor can reasonably expect ARB to either “save” them from wasting their investment funds or guide them toward “worthy” investments.

The above notwithstanding, we should note that, in Resolution 09-31, the Board found the LCFS, as approved, meets the criteria in HSC §38562. HSC §38562(b) provides, in part, that the Board:

- *“(1) Design the regulations, including distribution of emissions allowances where appropriate, in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California, and encourages early action to reduce greenhouse gas emissions.” [emphasis added].*

Thus, the Board has already found that the LCFS, as approved, already maximizes the total benefits and minimizes the costs to Californians, as well as encourages early action to reduce greenhouse gas emissions. These are all consistent with the commenters’ points with regard to investments in transportation fuels.

E-36. Comment: As compliance pathways become clearer over time, it will be essential that CARB conduct a rigorous multimedia assessment to avoid a repetition of the events that surrounded the use of MTBE. As part of the adopting resolution, AQMD staff therefore recommends that the Board commit to a rigorous multimedia assessment for any new fuel formulation before it is introduced in significant commercial quantities. (SCAQMD1)

The last time CARB adopted a new gasoline formula, there were unintended but serious water quality problems from the new fuel additive MTBE. Because of that experience, the State now requires extensive environmental impact analysis before a new standard is proposed. It is imperative that you do as much research and testing as possible before moving forward with this rule to protect not only the environment but public health. Has the staff completed and have you reviewed the analysis required under the HSC? (SFVMAPA)

Response: We agree in part with the suggestion in E-36. As noted previously, the Board found in Resolution 09-31 that the LCFS does not, by itself, constitute a motor

vehicle fuel specification necessitating a multimedia evaluation pursuant to HSC section 43830.8. However, the Board directed the Executive Officer to work with petroleum refiners, biodiesel and renewable diesel producers, and other stakeholders to complete the ongoing multimedia evaluation for biodiesel and renewable diesel and propose, as appropriate, motor-vehicle fuel specifications for biodiesel and renewable diesel by December 2009. Because of developments in that ongoing evaluation, staff anticipates the fuel specifications for biodiesel and renewable diesel will not be ready for the Board's consideration until sometime in 2010.

With regard to other fuels, there is no need to add the requested commitment to the resolution because such a commitment is already embodied under State law and in the LCFS language itself. The LCFS notwithstanding, any new fuel formulation that isn't already subject to an existing fuel specification is not permitted to be sold, supplied, or offered for sale in California unless it is subject to and meets an applicable motor-vehicle fuel specification or is otherwise permitted for sale under State law (e.g., allowed for sale under an experimental fuel permit pursuant to Division of Measurement Standard regulations). Thus, for a new fuel formulation that isn't already subject to an existing fuel specification, the ARB or DMS would first have to promulgate a fuel specification for that fuel formulation. For ARB, the establishment of such a new motor-vehicle fuel specification would have to be accompanied with a multimedia evaluation conducted pursuant to HSC section 43830.8. This was discussed in the Staff Report on pages V-32, V-33, VII-34, and VII-35. The LCFS regulation already provides for a pre-sale multimedia evaluation requirement, and such multimedia evaluations are to be conducted as part of the establishment of new motor-vehicle fuel specifications (17 CCR §95487(a)).

It is important to note that, unlike the MTBE situation, the LCFS does not involve the adoption of a new gasoline formula or a new formula for any other transportation fuel. As noted, the Board found that the LCFS does not, by itself, establish a motor vehicle fuel specification. Therefore, the LCFS does not dictate to a fuel producer how to make a compliant fuel and what components to put into it; the LCFS simply puts a cap on the carbon intensity of all the fuels that producer introduces into the California market and let's the producer determine the best way to do that as provided in the regulation. An analysis of the environmental and public health impacts of a specific fuel formulation conducted pursuant HSC section 43830.8 is impractical to conduct until ARB establishes new specifications for such a fuel; as noted above, when ARB staff proposes a new fuel specification for the Board's consideration, a multimedia evaluation conducted pursuant to HSC section 43830.8 will be conducted. Until such a proposal is made, the Board found that the "functional equivalent" multimedia assessment conducted by staff and presented in the Staff Report provides the best available assessment of the environmental and public health impacts for the LCFS regulation.

E-37. Comment: We don't know what the fuel will do to our equipment, to our engines. We're just seeking "indemnification [*sic*] from the fuel." We just ask for it to be tested before we go forward with it. Also, we want to know the recipe for the reformulation. We want to know the process on where the product's coming

from and how it's being added. And we also want to know how much it's going to be at the pump, the end users. (WD)

Response: The issue of whether ARB can indemnify end users for their use of fuels is addressed more fully in the response to J-13. Simply put, ARB cannot indemnify an end user, fuel producer, or any other party without express statutory authorization.

Engine performance and durability impacts, and the testing to determine such impacts, are considered during the rulemaking process to establish new fuel specifications. Because the LCFS does not establish new fuel specifications, ARB staff will consider such impacts when we propose implementing regulations to establish new fuel specifications (e.g., for biodiesel and renewable diesel in 2010, as noted previously). To the extent the LCFS can be met without the need for new fuel specifications to be established, no analysis of engine impacts would be necessary (i.e., the fuel producers would simply comply with existing fuel specifications but reduce the carbon intensity by purchasing LCFS credits, switch blendstock suppliers to those who can supply the same blendstock at a lower carbon intensity, etc.).

Because the LCFS does not establish fuel specifications, it follows that we cannot know for certain what the "recipe" will be for compliant fuels. However, staff's analysis of how lower carbon-intensity blendstocks (e.g., ethanol) are made and added to make finished fuels (e.g., gasoline or E10) is presented in the Staff Report, pages III-1 through III-21. The costs for the LCFS regulation, including staff's analysis of economic impacts to end users, are also presented in the Staff Report (*Id.* at VIII-39 through 41).

E-38. Comment: More recently, ARB prepared a California Environmental Quality Act (CEQA) functionally equivalent document (FED) that analyzed the potential adverse environmental impacts of the Proposed [AB 32] Scoping Plan. In the FED, ARB highlighted the impacts to air and water quality and land use planning associated with the biofuels pathways of the LCFS. The ARB made a number of specific findings with regard to potential impacts from the production and use of biofuels on emission sources, increased water demand, degraded water quality, and land resources. Further, in several sections in the FED, ARB determined that additional analysis of these issues will be required as part of the LCFS regulatory process. Thus, it is clear that ARB has yet to evaluate sufficiently the environmental impacts associated with increased use of biofuels and that further CEQA analysis is necessary as part of the LCFS regulatory process.

However, the statutory requirement to comply with CEQA (Public Resources Code, § 21000 et seq.) and the regulation of fuels (HSC § 43830.8 et seq.) are separate and distinct. Compliance with CEQA is therefore not a substitute for the statutory requirement to complete a multimedia evaluation when adopting a motor vehicle fuel specification, and any attempt by ARB to do so would be improper. (WSPA1)

Response: We disagree. As discussed in responses to Comment E-1, the Board found in Resolution 09-31 that the LCFS regulation does not, by itself, establish a motor vehicle fuel specification and, therefore, does not trigger the multimedia evaluation requirements specified in HSC § 43830.8. The reasons for this determination were set forth in the ISOR at pages V-26 through V-33.

Because the multimedia evaluation requirements were not triggered by this regulatory action, the commenter's characterization (that the Staff Report's CEQA analysis is an attempt at substituting for the HSC § 43830.8 requirements) is misplaced. As noted in the Staff Report (*Id.* at V-33), it is prudent to conduct a functional equivalent to the multimedia evaluation. This was to ensure that, to the extent feasible, the potential environmental and public health impacts from implementation of the LCFS were assessed, even though such an assessment is not required under the plain language of HSC § 43830.8. This assessment is contained in the CEQA analysis, which was presented in detail in the Staff Report, pages VII-1 through VII-36.

The fact that a multimedia assessment (conducted pursuant to HSC § 43830.8) and a CEQA analysis (conducted under PR § 21000 et seq.) appear to be similar is a mere artifact of their respective statutory requirements; they appear similar simply because these two separate and distinct statutes contain similar requirements for evaluating impacts on air, water, soil, and public health.

E-39. Comment: We question whether the earlier limited multimedia evaluation for ethanol needs further evaluation to incorporate other feedstock pathways and processing beyond the singular assumptions made earlier. (WSPA1)

Response: We disagree, and the commenter has provided no specific information that would indicate the assumptions and other bases for earlier multimedia evaluations involving ethanol are no longer applicable. As noted in responses to Comment E-31, the Board found that a new multimedia evaluation pursuant to HSC § 43830.8 is not required for the LCFS because it does not, by itself, establish motor vehicle fuel specifications for any fuel. With that said, the staff plans to conduct a full multimedia evaluation for a fuel whenever the Board establishes a new motor vehicle fuel specification for that fuel, on discussed on pages V-32 and V- 33 of the ISOR. Currently, ARB staff is evaluating potential rulemakings in 2010 for compressed natural gas, biodiesel/renewable diesel, and E85. To the extent these rulemakings establish new motor vehicle fuel specifications, ARB staff will assess the need to conduct full multimedia evaluations for those rulemakings pursuant to HSC § 43830.8.

E-40. Comment: Under HSC section 43830.8, ARB must conduct a multimedia evaluation before adopting a motor vehicle fuel regulation such as the LCFS. Specifically, ARB may not adopt any regulation that establishes a specification for motor vehicle fuel unless that regulation, and a multimedia evaluation conducted by affected agencies and coordinated by ARB, are reviewed by the independent California Environmental Policy Council ("Council"). ARB is permitted to adopt a regulation without a multimedia analysis only if following an

initial evaluation of the proposed regulation, the Council “conclusively determines that the regulation will not have any significant adverse impact on public health or the environment” (Id. at §43830.8(i)). The Council has not made this conclusive determination regarding the LCFS and has no basis for making such a determination. (WSPA1)

Response: The commenter misreads the plain language of HSC §43830.8(a) and mischaracterizes the language of §43830.8(i). HSC §43830.8 is structured so that:

- (1) no multimedia evaluation is required if the Board’s action does not establish a motor-vehicle fuel specification in the first place,
- (2) if the action does establish a motor-vehicle fuel specification, the Board does not have to conduct a multimedia evaluation if the Board finds, and the Council agrees, that there are no significant adverse environmental and public health impacts (the so-called “negative declaration” or “neg-dec” provision), and
- (3) if the action does establish a motor-vehicle fuel specification, the Board must conduct a multimedia evaluation and submit it to the Council’s for its review if the Board does not the negative declaration under (2) above.

Section 43830.8(a) specifies the threshold question that determines the applicability of the statute:

“(a) The state board may not adopt any regulation that establishes a specification for motor vehicle fuel unless that regulation, and a multimedia evaluation conducted by affected agencies and coordinated by the state board, are reviewed by the California Environmental Policy Council established pursuant to subdivision (b) of Section 71017 of the Public Resources Code.”

Simply put, HSC §43830.8(a) initially asks, “Does the proposed ARB regulation establish a motor-vehicle fuel specification in the first place?” If the answer to this threshold question is no, then the remaining provisions of HSC §43830.8 never come into play, including but not limited to the “negative declaration” provision noted by the commenter in HSC §43830.8(i), which provides:

*“(i) Notwithstanding subdivision (a), the state board may adopt **a regulation that establishes a specification** for motor vehicle fuel without the proposed regulation being subject to a multimedia evaluation if the council, following an initial evaluation of the proposed regulation, conclusively determines that the regulation will not have any significant adverse impact on public health or the environment.” [emphasis added].*

From the above language, it is clear that the negative declaration provision applies only when ARB has determined that its action establishes a motor-vehicle fuel specification in the first place.

As the administrative agency in charge of interpreting and implementing the statute, ARB is the sole agency tasked with determining whether its adoption of a new regulation establishes a new motor-vehicle fuel specification. If the Board's answer to the threshold question is negative, then the Council's role never comes into play. This is because the Council has no authority under the statute to provide its own answer to the threshold question. Further, nowhere in the statute did the Legislature grant the Council authority to question the Board's answer to the threshold question. Rather, the Council is simply tasked with reviewing multimedia evaluations submitted to it by the Board staff, provided ARB made the determination that such a multimedia evaluation was required in the first place.

As discussed in responses to Comment E-31, the Board emphatically found in Resolution 09-31 that such a multimedia evaluation requirement was not triggered by adoption of the LCFS. Therefore, because no multimedia evaluation for the LCFS is required under the statute, it follows that there is no legal basis for the commenter's contention that ARB is required to submit a multimedia evaluation for the Council's review and approval.

Interstate Commerce Clause

E-41. Comment: The proposed regulation violates the Commerce Clause of the U.S. Constitution. Under the Commerce Clause, states may not enact a statute that directly regulates or discriminates against interstate commerce, or favors in-state economic interests over out-of-state interests. Here, because California harvests relatively little of the country's corn, the land use "penalty" for corn-based biofuels under the proposed regulation necessarily regulates extra-territorial conduct and effectively favors in-state interests over out-of-state interests. Furthermore, while California has a legitimate interest in protecting its citizens against the effects of global warming, it may not do so in a manner that places an excessive burden on interstate commerce. Including ILUC in the proposed regulation will place an excessive burden on interstate commerce by arbitrarily denying the corn ethanol industry access to the nation's largest market of transportation fuels. (GE3)

Response: The Commerce Clause grants to Congress the power to regulate interstate commerce. The Supreme Court has construed it to encompass an implicit or "dormant" restriction on the states from enacting certain kinds of laws and regulations affecting interstate commerce even where Congress has not spoken.

The courts will review with "strict scrutiny" – and almost always invalidate – a state regulation found to discriminate against interstate commerce. This includes a regulation that is discriminatory on its face by expressly treating out-of-state entities differently than in-state entities. An example would be a regulation that prohibits the import of most waste that originates out-of-state. The commenter does not suggest that the LCFS is discriminatory on its face, and in any event this is clearly not the case. The carbon intensity of ethanol from corn reflects the same land use effect whether it is

produced in-state or out-of-state. Strict scrutiny will also be applied to a regulation that, while facially neutral, has the practical effect of being discriminatory. But the land use change element imposes no hurdles or additional costs for out-of-state corn ethanol that do not apply to corn ethanol produced in the state.

The courts also require a "strict scrutiny" review for a state regulation that attempts to regulate beyond the state's jurisdiction or otherwise has the practical effect of regulating conduct beyond the state's boundaries. (*Healy v. Beer Inst.*, 491 U.S. 324, 336-7 (1989).) The commenter asserts that the indirect land use change element of the LCFS "necessarily regulates extra-territorial conduct" because California harvests little of the country's corn. Yet on its face the LCFS regulation applies only to those who produce transportation fuels in California or import them into California. If a batch of ethanol is produced outside California and is not brought into California, the regulation imposes no requirements on the out-of-state producer. The focus of the regulation is only on fuels that are used as transportation fuels in California, whether originally produced in the State or imported from outside the State. And the regulation will not have the practical effect of controlling commerce that occurs wholly outside the boundaries of California.

When a state law or regulation is not discriminatory or extraterritorial, a court considering a dormant Commerce Clause challenge will apply a "balancing test" first described by the Supreme Court in *Pike v. Bruce Church, Inc.*, 397 U.S. 137(1970): "Where the statute regulates even-handedly to effectuate a legitimate local public interest, and its effects on interstate are only incidental, it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits." (*Pike* at 32). The LCFS and its treatment of the indirect land use effects associated with certain biofuels, meets the *Pike* test.

While the commenter acknowledges that California has a legitimate interest in protecting its citizens against the effects of global warming, the great importance of that interest to California is set forth in the Scoping Plan and must be emphasized. The question becomes whether the "burden" the indirect land use component imposes on interstate commerce is clearly excessive in relation to California's interest in ameliorating the adverse impacts of global warming in the state. In comments addressed elsewhere in this FSOR, the commenter asserts that there is no sound scientific or policy basis for including the specified land use effects in determining the carbon intensity of corn ethanol. This is why the commenter claims the land use effect provisions "arbitrarily" harm interstate commerce in corn ethanol. The responses to those comments effectively rebut the claims of arbitrariness, thus demonstrating the land use change approach does not impose an excessive burden in relation to California's interests in addressing the adverse impacts of climate change. So a lot of the point will be his analysis is premised on the science; if we're right, not having the LUC part loses all the benefits.

Compliance with Administrative Procedure Act

E-42. Comment: There are many missing pieces of the LCFS regulation as proposed,

including key carbon intensity values and a mechanism for tracking and reconciling CI credits and debits. We believe that an incomplete rule cannot satisfy the California APA clarity requirement for agency rules. The APA defines “clarity” as meaning that the rule is “written or displayed so that the meaning of regulations will be easily understood by those persons directly affected by them.” The proposed LCFS cannot be easily understood by the persons who will be directly affected, because key elements are missing. (Manaster/ WSPA 4/23/09 letter)

Response: We do not believe that key or necessary elements are missing from the regulation as finally adopted such that the regulation is unclear under the APA. While the original proposal did not provide for carbon intensity values for particular fuels and pathways to be included in the regulation itself, this has been changed as the result of comment. The Lookup Tables are now in the regulation. And there is a process for the expeditious identification of customized lookup table values and new pathways generated by the California-Modified GREET, consistent with the APA. With respect to the mechanism for tracking and reconciling carbon intensity credits and debits, we believe sections 95484 and 95485 as adopted provide sufficient direction to regulated parties on how to comply with the regulation.

E-43. Comment: CARB cannot conduct a hearing that adopts a diesel LCFS in April when the elements required by the APA will not be completed until December, when almost all the regulatory elements are required to be ready. (IWLA)

Response: The diesel LCFS element of the regulation is not being finally adopted until the supplemental comment process is completed and the carbon intensity values for biodiesel and renewable diesel are included. This is consistent with APA requirements.

F. ENVIRONMENTAL IMPACTS

This section addresses comments and responses related to the environmental analysis, including: impacts on GHG emissions, impacts on air quality, other environmental impacts, public health analysis, environmental justice and health risk assessment, California biorefineries, treatment of electricity, credits for electricity, treatment of hydrogen, credit trading, and the adequacy of the environmental analysis.

Greenhouse Gas Emissions

F-1. Comment: The increased power plant emissions caused by an increase in demand for electricity as a transportation fuel will negate the benefits of the LCFS. (CERA2)

Response: In the ISOR, staff analyzed the GHG emissions from additional electricity demand (see Staff Report pp. III-11 through III-13). Due to the efficiency of electric vehicles, California's clean power generation mix, the move toward increasingly higher percentage of renewable sources of electricity (see Staff Report p. II-4), and the expectation that electric vehicle owners will take advantage of cheaper rates for off-peak charging, we estimated a substantial decrease in the GHG emissions as a result of electric vehicle use. Scenario 2, for example, includes a large number of advanced vehicles (plug-in hybrids, battery electric vehicles, and fuel cell vehicles). The electric vehicles in this scenario would result in a decrease of GHG emissions of 5.6 MMT CO₂e.

F-2. Comment: The International Energy Agency estimates that over the next 23 years, the world could produce as much as 147 million tons of agrofuels. This will be accompanied by massive amounts of carbon and nitrous oxide emissions, erosion, and over 2 billion tons of waste water. Remarkably, this fuel will barely offset the yearly increase in global oil demand, now standing at 136 million tons a year – without offsetting any of the existing demand. (RAN1)

Response: As indicated in the ISOR in Chapter VI, the LCFS regulation is expected to displace approximately 10 percent of the petroleum fuel in California by 2020. Also, as shown in Chapter VII of the ISOR, the LCFS regulation is expected to result in no additional adverse impacts to California's air quality due to emissions of criteria and toxic air pollutants. Based on the best available data, there may be a benefit in further reducing criteria air pollutants from the 2020 projected vehicle fleet. See also response to Comment F-3. At this time, implementation of the LCFS is not expected to expose people or structures to potential substantial adverse effects that involve risk of loss, injury or death from rupture of a known earthquake fault, strong seismic ground shaking, seismic-related ground failure, landslides, or result in soil erosion or be located on a geologic unit or soils that is unstable. In regards to waste water, please see the ISOR, Section VII.D., pages VII-24 to VII-26. For responses regarding water impacts, please see responses to Comments F-24 through F-40.

F-3. Comment: Refining dirtier oil will increase GHG emissions, toxic emissions, and pollution. (CBE1, CBE2, CBE3)

Response: World demand for petroleum is increasing. By reducing California's demand for petroleum, the LCFS will help slow the increase in world demand for dirtier oil. In California, oil refineries must continue to meet federal, state, and local requirements including permit conditions. The LCFS does not change those requirements. The LCFS does track the use of high intensity crude not previously a substantial part of California's crude slate and requires the associated GHG emissions to be included in regulated parties' reported GHG emissions and reduced.

F-4. Comment: The Low Carbon Fuel Standard should be challenging but achievable. Section 2 of the draft outline states that the Low Carbon Fuel Standard will require a 10 percent reduction in the full life cycle intensity of gasoline and, separately, a 10 percent reduction in the full life cycle carbon intensity of diesel fuel by 2020.

CARB has not yet conducted a feasibility assessment for such requirements, and thus the achievability of these standards is not known. Earlier in this process, CARB did an assessment of the feasibility of a 10 percent reduction in carbon intensity but that assessment was conducted on a very different set of assumptions from the ones that are now being considered. There are two significant differences between CARB's earlier evaluation of the technological feasibility and the current draft outline. Firstly, the earlier analysis considered a 10 percent reduction in the carbon intensity of transportation fuels as a whole, while the current draft would impose separate standards on gasoline and diesel. Secondly, the earlier analysis presumed that blending additional ethanol and FAME into fuels would provide a significant proportion of the reduction and this presumption is now being re-examined in light of the land use change issue. (SHELL)

Response: The initial feasibility assessment that is being referred to was conducted by researchers at the University of California (UC) Berkeley and UC Davis. In support of an LCFS, UC professors Daniel Sperling and the late Alexander Farrell directed a team of UC colleagues that developed two significant reports that provided an initial framework for the LCFS. These two reports established the technical feasibility of an LCFS, identified many of the significant technical and policy issues, and provided a number of specific recommendations. These comprehensive reports were the backbone of ARB staff's initial efforts to develop the LCFS. However, the staff did not follow all of the recommendations, as subsequent technical analysis resulted in staff identifying different approaches and compliance scenarios.

As mentioned in the ISOR, the staff prepared several scenarios for achieving both the gasoline and diesel standards in order to determine the feasibility of the LCFS. Four of the scenarios pertain to gasoline and fuels that can substitute for gasoline and three pertain to diesel and its substitute fuels. Each scenario describes a compliance path

involving a different combination of advanced renewable fuels, and advanced electric and hydrogen-powered vehicles. The compliance scenarios demonstrate compliance is possible, given what is currently known about the future availability of alternative fuels and vehicles. In addition, the compliance scenarios show that compliance is not contingent upon the availability of only a limited number of alternative fuel-vehicle combinations.

F-5. Comment: Unfortunately, not only will LCFS fail to meet the GHG reduction goal, it will actually cause GHG emissions increases and major harm to human and environmental health. The draft LCFS fails to meet the primary goal of reducing GHG emissions because it 1) includes corn ethanol (which will increase fuel carbon content), 2) fails to address the switch to heavy crude oil use by refineries in the state (higher carbon), and 3) relies on unreliable out-of-state pollution trading. The draft LCFS also causes harm to the environment (major urban air and water pollution and damage to wildlife) and greatly adds to already-severe global food shortages. (CBE3)

Response: First, staff has done substantial analysis of the effects of the LCFS on GHG emissions and finds that there are substantial GHG benefits provided by the regulation. Staff presented its analysis of the GHG benefits of the LCFS in the ISOR in VII pages 3-7. Second, there are several viable corn ethanol pathways that meet the standard through 2020 and do not increase the carbon content of the fuel supply. The carbon intensity of corn ethanol takes into account not only the direct emissions from the production, transportation, and use of corn ethanol, but also its direct and indirect impacts on the land. For more information on how the carbon intensities are calculated, please see the responses to comments in Section III.C. (Land Use Change) of this FSOR. For addressing the switch to heavier crude, see response to Comment F-3. Regarding out-of-state pollution trading, the LCFS regulation does not allow credits generated outside of the LCFS program to be used in the LCFS program. The LCFS regulation does provide for the possibility of exporting LCFS credits to AB32 and other greenhouse gas initiatives, subject to the authorities and requirements of those programs. As we approach LCFS credit generation in 2011, ARB staff will consider the need to limit the export of LCFS credits to unreliable out-of-state pollution trading programs.

F-6. Comment: Ban corn ethanol as part of the LCFS (and in Reformulated Fuels requirements) due to increased GHGs, increased smog, and other severe environmental impacts. While this is politically tough, it is the right and necessary thing to do. There is no longer any scientific justification for use of corn ethanol in California as a low carbon fuel. (CBE3)

Response: The Board found that the LCFS regulation is expected to significantly reduce emissions of GHGs, that overall the regulation is expected to result in no significant additional adverse impacts to California's statewide air quality due to criteria and toxic pollutants, that based on the best available data, there may be a benefit in further reducing emissions from the 2020 vehicle fleet, and that the benefits to human

health, public safety, public welfare, or the environment justify the costs of the proposed regulation. Also, the use of ethanol as a motor vehicle fuel is addressed in the CaRFG3 regulations which mitigate emissions from the use of ethanol, whether derived from corn or another feedstock. Rather than ban corn ethanol or ethanol from other agrofuels, the approach selected was to assign a carbon intensity value to the use of such fuels which includes the indirect land use impacts. The indirect impacts consider the increase in food production on lands not previously used for this purpose to replace the lost production. This leads to agrofuels having carbon intensities that make them less attractive for use to reduce the carbon intensities of petroleum fuels. It also provides an incentive to produce alternative fuels that do not have this impact such as cellulosic- or algae-derived fuels. Thus, agrofuels are expected to be used until second and third generation fuels are brought online to meet our demands. Finally, we have assessed the GHG impacts of corn ethanol, including land use change impacts, and believe that the market will mediate the volume of corn ethanol used. When this analysis was performed, we assumed that 300 million gallons of corn ethanol would be used in California through 2020 and that all of the corn ethanol would be produced using techniques that provide GHG benefits.

F-7. Comment: Increasing ethanol content of gasoline to 10 percent is not only counterproductive for reducing greenhouse gases, but extremely harmful to the environment. (CBE3)

Response: The increase to 10 percent ethanol by volume is not required by the LCFS. This increase would have happened regardless of the LCFS, which is why 10 percent ethanol is included in the baseline of the LCFS. The increase to 10 percent ethanol is a result of a number of factors, including the federal renewable fuels program, and also as a means to mitigate permeation emissions under CaRFG3. The emissions impacts of ethanol in gasoline are addressed as part of the CaRFG3 rulemaking. See also response to Comment F-21 on addressing the impacts of ethanol in gasoline.

F-8. Comment: The draft LCFS also causes harm to the environment (major urban air and water pollution and damage to wildlife) and greatly adds to already severe global food shortages. (CBE3)

Response: Responses F-1, F-3, F-5 and F-6 above address the concerns of increases in greenhouse gas emissions. Regarding water impacts, please see responses to Comments F-24 through F-40. For responses regarding food shortages, please see Section H (Food Versus Fuel).

F-9. Comment: The draft Low Carbon Fuel Standard will cause increased greenhouse gases, and severe smog, water impacts, food shortages, and more. (CBE3)

Response: Responses F-1, F-3, F-5 and F-6 above address the concerns of increases in GHG emissions. For responses regarding water impacts, please see responses to

Comment F-24 through F-40. For responses regarding food shortages, please see Section H (Food Versus Fuel).

F-10. Comment: Global warming is a worldwide problem that cannot be solved by California alone. California will need to be part of a national and international effort to reduce global warming. If the rest of the country and world does not act to the same degree as California, the LCFS will be very costly to Californians but will not achieve meaningful reductions of global warming. There is a concern that other counties are reducing their commitment to global warming reduction. One commenter cites that France will no longer be supporting an effort to reduce global warming. (CBOC1, CBOC2, NFIB, SJCHCC3, WEITZMAN1)

Response: ARB recognizes that significant climate change will require action on regional, state, national and international levels. As discussed in the Executive Summary of the Staff Report and in Chapter IV of the Scoping Plan, California has been a leader in working with other state agencies, U.S. EPA, various states, and international organizations to reduce greenhouse gas emissions and to reduce global warming. On November 18 and 19, 2008, the Governor and other U.S. governors co-hosted a Governors' Global Climate Summit which began a partnership with leaders from the U.S, Australia, Brazil, Canada, China, India, Indonesia, Mexico, the European Union, and other nations to reduce greenhouse gas emissions. The Governors' Global Climate Summit 2 was held on September 30-October 2, 2009 in Los Angeles, California. At the summit, 31 government officials from eight countries signed specific agreements and a declaration acknowledging the threat of climate change and committing to collaboration on deforestation, technology transfer, and information sharing.

California is also a partner in the Western Climate Initiative, with members that also include Arizona, New Mexico, Oregon, Washington, Utah, and Montana and the Canadian Provinces of British Columbia, Manitoba, Ontario, and Quebec. At the national level, the federal revised Renewable Fuels Standard (RFS2), which is part of the Energy Independence and Security Act of 2007 (EISA), mandates targets for lower carbon intensity fuels: 36 billion gallons of biofuels to be sold annually by 2022, of which 21 billion gallons must be advanced lower carbon intensity biofuels.

The LCFS program is one component of California's landmark climate change initiative that can be a model for other entities in the U.S. and internationally. As discussed in the Executive Summary of the Staff Report, an important goal of the LCFS is to establish a regulatory framework that is capable of being exported to other jurisdictions. Chapter II of the Staff Report identifies other areas of the United States (Northeast and Mid-Atlantic States) and several countries that have developed or are planning to develop a Low Carbon Fuel Standard similar to California's LCFS. In December 2008, the European Parliament adopted a number of measures to address climate change, including a Biofuel Directive that requires that fuel suppliers to reduce GHG emissions on a lifecycle basis by up to 10 percent by 2020. Fuel suppliers will be required to report on the lifecycle GHG emissions of the fuel beginning in 2011.

Finally, ARB Board Resolution 09-31, adopted on April 23, 2009, directed staff to coordinate efforts, to the extent feasible, with U.S. EPA, the European Union, and other regional, national and international agencies considering the adoption and implementation of an LCFS regulation or similar programs.

F-11. Comment: California needs to determine how much the LCFS will reduce global warming. It is unlikely that the LCFS alone will result in any measurable climate change and reduction of global warming. One commenter provides an independent analysis of the effect of LCFS using a climate model known as MAGICC (Model to Assess Greenhouse Gas Induced Climate Change), the model used by the Intergovernmental Panel on Climate Change (IPCC) to show that the impact of the LCFS would be undetectable. (WSPA1, WEITZMAN, SJCHC3, NFIB, CBCOC1)

Response: ARB recognizes that GHG emission reductions by the LCFS alone will not result in significant climate change. As discussed in Chapter I of the Staff Report (ES-35 to ES-39) and in the Scoping Plan, California is the fifth largest emitter of greenhouse gases on the planet and contributes approximately two percent of the total worldwide GHG emissions. The LCFS program is only one of several GHG reduction measures that comprise California's Climate Change program discussed in the Scoping Plan. The Scoping Plan identifies a comprehensive and coordinated set of GHG emission reduction strategies throughout the economy.

The LCFS program is expected to reduce GHG emissions approximately 16 million metric tons per year in California, contributing approximately 10 percent of California's expected GHG reductions identified in the Scoping Plan to achieve the long term goal of reducing California's GHG emissions by 80 percent by 2050. California's strategy is consistent with the recommendations of the IPCC, which points out that in order to avoid a future catastrophic increase in global mean surface temperature, GHG emission reductions should apply to all major GHG emitters globally and should not rely on a single policy. Indeed, as discussed in the Scoping Plan, California recognizes that, despite any uncertainties in our understanding of climate change, the steady buildup of GHGs in the atmosphere poses significant long-term environmental and public health risks. Also see response to Comment F-10.

F-12. Comment: ARB should track mass emissions of greenhouses gases, in addition to carbon intensity, as part of the LCFS implementation process. ARB should establish a baseline GHG emission level and track actual GHG emissions associated with on-road transportation fuels in order to track the efficacy of the LCFS program over time. (SCAQMD1)

Response: ARB maintains a GHG Emissions Inventory pursuant to Assembly Bill 1803. ARB updates the statewide GHG inventory on an annual basis, typically during the first quarter. The inventory tracks the mass emissions of GHGs across all major economic sectors, including on-road transportation. The inventory is constructed as a time series so that year-to-year changes in statewide emissions by sector, fuel type,

and other relevant parameters may be analyzed. ARB will assess the efficacy of the LCFS as we develop periodic updates to the regulation.

F-13. Comment: ARB's emissions analysis should take into account the various affects on potential OEM vehicle regulation compliance scenarios. These scenarios may allow for automakers to actually produce more ULEVs when complying and therefore would increase emissions. How is it assumed that additional ZEV sales above the ZEV mandate requirement would replace ULEV sales? Shouldn't emissions increases from less PZEV and more ULEV sales be accounted for in the LCFS emissions analysis now and not accounted for in future regulations? (SIERRAR)

Response: The LCFS regulation seeks to reduce carbon emissions from transportation fuels and does not require OEMs to produce any specific vehicle types. The LCFS is part of an overall GHG reduction goal while the comments concern criteria pollutant emissions. The goals for the ZEV regulation are to reduce GHGs and criteria pollutants as well as assist in petroleum reduction.

The LEV and ZEV regulations are currently undergoing review and new standards will be proposed in the upcoming years. The comments presented pertain to these regulations and, as these regulations are revised, the crossover impacts on emissions will be analyzed. ARB's goal is to ensure that both the ZEV and LEV regulations achieve maximum benefits for emissions reductions. It is technically feasible to have a minor increase of emissions from over compliance. These emissions would come from the loss of vehicles with zero evaporative systems. Any increase in ULEVs or vehicles with higher emissions will be severely limited by the very stringent NMOG fleet average standard. ARB does not foresee any failure to comply with current ZEV and LEV regulations as a result of complying with the LCFS.

Localized Air Quality

F-14. Comment: The ARB should ensure that the LCFS will not result in a decrease in GHG emissions at the expense of increased emissions of smog producing pollutants. (CHCC2, CBE3, CBCOC1)

Comment: The LCFS will cause increased emissions of smog-producing pollutants. (CBE3)

Response: For regulated parties to comply with the LCFS, new fuel facilities may need to be built. However, the LCFS regulation is not expected to adversely impact California's air quality due to emissions of smog-producing air pollutants. Overall, the regulation may result in a reduction in criteria pollutant emissions from the 2020 vehicle fleet based on best available data. New facilities are required to comply with state and local air quality regulations associated with New Source Review programs already in place. In addition, staff is currently preparing a biorefinery siting guidelines document that is designed to assist local air districts when permitting new fuel production facilities.

In addition, the use of ethanol, biodiesel, or other fuel as a vehicle fuel must meet existing fuel regulations that are designed to reduce or at least ensure there is no increase in emissions. We also anticipate that new specifications may need to be adopted to ensure no increase in emissions result from the increased use of particular fuels, such as the activity underway to develop biodiesel specifications.

F-15. Comment: The ARB should clarify the air quality impacts of each fuel path over the entire fuel cycle. (ALA5)

Response: The fuel lifecycle analyses prepared for fuels subject to the LCFS are designed to estimate the fuel carbon intensity. The fuel production facilities will be covered, however, by stringent criteria pollutant and air toxics regulations that have already been adopted by ARB and the local air districts. These regulations will continue to result in significant reductions in air pollution emissions, exposure, and health-based risk in California.

F-16. Comment: So to address these issues, we support the proposed resolution and regulatory language; develop a framework for evaluating these impacts, air quality public health impacts, as we move forward; including direction to develop guidelines for local review of air quality emission impacts; direction to conduct a comprehensive public health analysis of the low carbon fuel standard; and direction to review and assess the air quality impacts of the standard on a statewide basis. (ALA5)

Response: ARB staff appreciates the support. As identified by the commenter, the Board directed staff, through Board Resolution 09-31, for projects directly related to the production, storage, and distribution of transportation fuel subject to the LCFS program, to participate in the environmental review of specific projects, evaluate the air quality impacts of these projects; and as appropriate, identify feasible measures to mitigate the local and regional impacts of these projects. This effort is to be coordinated with local air districts, lead agencies for the preparation of environmental impact statements under the California Environmental Quality Act; companies proposing to build new production, storage, and distribution facilities; and environmental and community representatives. Though not necessary to be completed prior to the final adoption of the regulation, the Board nevertheless recognized the value of the listed activities in facilitating the implementation of the regulation.

F-17. Comment: Corn ethanol should be banned in the LCFS program due to increased GHGs, increased smog, and other severe environmental impacts. (CBE3, CMCC, SVHCC, CBE1)

Response: See response to Comment F-6.

F-18. Comment: The LCFS should be strengthened to ensure that it protects California's air quality. (SALVARYN, SALAZAR)

- **Response:** The LCFS does not exempt any production or use of fuel from any other applicable local, state or federal requirements. The fuel production facilities subject to the LCFS regulation will also be covered by stringent criteria pollutant and air toxics regulations that have already been adopted by ARB and the local air districts. These regulations will continue to result in significant reductions in air pollution emissions, exposure, and health-based risk.

F-19. Comment: Growth in fuel production should only occur with a concurrent reduction in non-GHG emissions. (CVAQ)

Response: The LCFS regulation is not expected to adversely impact California's air quality due to emissions of criteria or toxic air pollutants. Based on available data, the regulation may result in a reduction in criteria pollutant emissions from the projected 2020 vehicle fleet. Local air districts will, with assistance from the ARB's biorefinery siting guidelines document, consider air quality issues when permitting new fuel production facilities.

F-20. Comment: In fact, available research suggests the opposite – increased ethanol concentrations in gasoline have been shown to increase NOx emissions from vehicles in the existing fleet and to increase permeation emissions of hydrocarbons from both on-road and off-road vehicles and equipment using plastic fuel tanks and elastomeric fuel lines. These impacts have been completely ignored in the ISOR. (WSPA)

Response: The CaRFG regulations require that emissions associated with the use of ethanol in gasoline, including emissions of NOx, be mitigated. Refiners are required to use the California Predictive Model to certify gasoline. To certify a gasoline in California, refiners must submit a fuel formulation that meets the equivalent emissions of a baseline non-ethanol fuel. The gasoline must be equivalent or less than in emissions for three criteria, NOx, ozone-forming potential, and toxic air contaminants.

F-21. Comment: SCAQMD found smog will increase due to adding ethanol to gasoline. Now ARB is mandating an increase in ethanol in gasoline, which is known to cause increased smog. Given the severe asthma epidemic, it is unbelievable that the ARB would allow the Low Carbon Fuel Standard to exacerbate smog by increasing smog precursor ethanol emissions, especially when this addition doesn't reduce GHG emissions. The increased ethanol emissions occur when ethanol permeates through vehicle seals and gaskets. This is a chemical oddity that occurs due to this mix of lower levels of ethanol with gasoline. At the March hearing, SCAQMD staff testified that gasoline would be cleaner without ethanol.

SCAQMD staff also testified that ARB's peak ozone planning temperature is too low (87° F instead of 95° F), which underestimates smog formation, since smog precursors including ethanol react on hot days to form ground-level ozone (smog). Ethanol permeation emissions are much higher at higher temperatures.

(CBE3)

Response: The issues raised were thoroughly addressed in the 2007 rulemaking for amendments to California reformulated gasoline (CaRFG). Note that ARB is not mandating an increase of ethanol in gasoline. The CaRFG3 regulations generally do not require the use of a specified amount of ethanol. However, ethanol is an oxygenate, and there is an oxygen content requirement. There is a minimum oxygen content requirement of 1.8 percent by weight for the South Coast area and Imperial County, from November 1st through February 29th. Outside of that requirement, refiners have the option to put from 0 to 3.5 percent by weight oxygen (0 to 10 volume percent ethanol) in CaRFG3.

There is another driving force for increasing amounts of ethanol in gasoline. The Federal Renewable Fuel Standard (RFS) requires increasing amounts of biofuels in transportation fuels through 2022. The RFS is expected to push ethanol in gasoline up to 10 percent by 2012 nationwide.

As a result of the CaRFG3 regulations, a 0 percent ethanol fuel will be as clean as a 10 percent ethanol fuel because both fuels are required to meet the same emission standards.

The South Coast air basin temperature profile covers not only the inland areas, but also the coastal areas. This temperature reflects the average temperature in all those areas. The EMFAC2007 model, which was used in the June 2007 amendments of the CaRFG3 regulations, is designed to show a temperature profile across the entire South Coast Air Basin of which Los Angeles County is one region. While on some hotter days the peak temperature of 87 degrees used in the model might be low compared to the actual temperature in Los Angeles County, it will most likely be higher than the actual temperature in the coastal regions. As mentioned, this was addressed in the 2007 CaRFG3 rulemaking record. See also response to Comment F-7.

F-22. Comment: The health issue relates to carcinogens, air toxins and particulates in the air that will be alleviated to some degree by ethanol, depending on blend levels. The oil companies handicapped the health of children with lead for more than half a century; they are doing the same with aromatics. (BCC2)

Response: The CaRFG regulations regulate eight fuel properties. Two of those eight fuel properties are for benzene (an aromatic) and total aromatics. Together these limits reduced benzene, a known carcinogen, by 50 percent and total toxic air contaminants on a potency weighted basis by 40 percent. In addition, particulate emissions from gasoline vehicles are decreasing even with the increased amount of ethanol. Refiners are required to use the Predictive Model to establish alternative limits to meet the same emissions requirements as a nonoxygenated fuel. The CaRFG3 regulations through the use of the Predictive Model require that emissions associated with increases of ethanol use in gasoline be mitigated. To certify a gasoline in California refiners must submit a fuel formulation that meets the equivalent emissions of a baseline MTBE fuel.

The gasoline must be equivalent or less than in emissions to three criteria: oxides of nitrogen, ozone forming potential, and toxic air contaminants.

F-23. Comment: ARB explains in the ISOR that at least two other vehicle studies are in the works, the Coordinating Research Council E-80 project, and the U.S. EPA Comprehensive Gasoline Light Duty Exhaust Fuel Effects Test Program to Cover Multiple Fuel Properties and Two Ambient Test Temperatures. Criteria pollutant and toxic emissions from motor vehicles using all fuels were estimated with the CA Modified GREET version 1.8b(47). At the March 27, 2009 LCFS workshop staff pointed out that they were waiting for this state/ federal program to begin after it was stalled in contract, but next month testing should be underway. Without these test results ARB's work is incomplete, and staff cannot claim with the requisite level of certainty that there will be no increases in toxic air contaminants when the testing has not even begun. Under a previous testing program, the EPA concluded that "ozone levels generally increase with increased ethanol use." The chemical variations of bioethanol fuel mixtures could thus exacerbate California's public health air quality crisis, in turn, creating additional disproportionate impacts within the state. (CERA1)

Response: The California Predictive Model database is comprised of 42 vehicle emission studies that include 10,368 observations, 1359 vehicles, and 336 fuels. Based on these 42 vehicle emissions, staff believes that there is a requisite amount of data to support their claims that there will be no increase in toxic air contaminants. The CaRFG3 regulations through the use of the Predictive Model require that emissions associated with increases of ethanol use in gasoline be mitigated. To certify a gasoline in California, refiners must submit a fuel formulation that meets the equivalent emissions of a baseline CaRFG fuel with 11 percent MTBE. The gasoline must be equivalent or less than in emissions to three criteria, oxides of nitrogen, ozone forming potential, and toxic air contaminants. The current California gasoline regulation ensures that there will be no increase in air toxics. The Predictive Model determines the emissions of the candidate fuel based on the 42 vehicle emission studies in its database. The two studies mentioned are to complement these studies. Also see response to Comment F-22.

Water Issues

F-24. Comment: A number of commenters raised concerns that the LCFS did not adequately address water quality and water supply concerns from biofuel production facilities and from agricultural production of transportation fuel feedstocks. (CERA1, CERA2, CRPE1, SIERRACLB2, SIERRACLB3, GE3).

Response: ARB acknowledges the importance of water quality and water supply concerns from biofuel production facilities and from agricultural production of transportation fuel feedstocks. During the LCFS rulemaking, ARB and the State Water Resources Control Board (Water Board) evaluated water quality and water use impacts, as a part of the environmental impact analysis for the LCFS.

As discussed in Chapters IV, VII and Appendix F for the ISOR, both ARB and the Water Board are aware of the potential water pollution issues associated with the projected ethanol and biodiesel production, both from the expanded agriculture activities and biorefinery activities. ARB and the Water Board staff evaluated water quality and water use impacts as a part of the environmental impact analysis for the LCFS. The analysis concluded that the risks of contamination are not likely to increase due to the close regulation of such facilities by local and state agencies.

The ISOR addresses full lifecycle water supply impacts associated with implementation of the LCFS in Chapter VII, Appendix F12, and Chapter IV. Table F12-2 identifies lifecycle water use for various fuel production pathways, including eight candidate fuels and seventeen scenarios; this table also addresses water quality issues for each of the fuel production pathways. Table VII-14 provides a worst case California water consumption estimate for various biofuels.

There are a number of regulations and permitting requirements that are in place to protect water quality and water supply in California. As stated in Chapter VII of the ISOR, the Water Board regulates wastewater discharge from production facilities, toxicity of wastewater discharges, and water quality related to ecology and other beneficial uses. The Regional Water Boards also have the authority to issue National Pollution Discharge Elimination System (NPDES) permits for discharges from fuel production facilities. The State Water Board regulates the storage of fuels by requiring permits for storage facilities, which are subsequently inspected annually for compliance. In addition, there are other regulatory limits on storage of fuels that do not necessarily require a permit. Disposal of liquid wastes to a local wastewater treatment plant is at the prerogative of the treatment plant management; they will not accept a wastewater stream of any kind if that would cause the treatment plant to exceed their NPDES permit and thus the production facility may be denied a permit.

Any new construction of a biofuel facility will be subject to regulatory and permit requirements of the State and Regional Water Boards under the California Water Code (which includes the NPDES permit provisions), and CEQA. Siting of any new biorefinery in California will need to confirm and address water availability with the Regional Water Board with jurisdiction, as well as with the local planning agency, early in the CEQA and permitting process. The proponent would need to secure a water supply from a local water district. The ownership of surface water use in California is regulated by the State Water Board, Division of Water Rights. If water cannot be secured locally, the proponent could consult with the Division of Water Rights to locate potential water transfer opportunities and apply for a Board ruling on transfers that involve a change in the place of use. The proponent may also have to obtain the permission of the Regional Water Board to ensure the availability of groundwater supplies in consideration of competing beneficial use(s) and minimum stream flow requirements if well water drafts from subsurface flows beneath a stream. ARB Board Resolution 09-31 acknowledges that although some new California biorefineries could use amounts of water that have the potential to result in a small adverse impact, CEQA

and State and Regional Water Board permitting requirements should mitigate any potential water supply impact by requiring a site-specific analysis and determination of water use.

By December 2009, ARB staff intends to develop a workplan for developing overall sustainability provisions for the LCFS, including water use and water quality issues, for consideration by the Board at its first formal public review scheduled for the end of 2011.

F-25. Comment: We ask the Board to include the water impacts of producing biofuels in the LCFS standard. The standard should factor in the costs of polluting groundwater and the stress on our water supply from biofuels production. California must avoid repeating the mistake of MTBE, which was added to gasoline to reduce air pollution but caused a tremendous groundwater pollution problem. ARB could determine appropriate costs for water impacts by using a probabilistic (insurance) approach, or allow the insurance industry to make the calculations and provide actual insurance to cover future groundwater cleanups. (SIERRACLUB2, SIERRACLUB3)

Response: The Staff Report/ISOR addresses potential water quality and water supply impacts of implementing the LCFS standard. ARB Board Resolution 09-31 recognizes that although some new California biorefineries could use amounts of water that have the potential to result in a small adverse impact, CEQA and State and Regional Water Board permitting requirements should mitigate any potential water supply impact by requiring a site-specific analysis and determination of water use. Although the goal of the LCFS standard is GHG reduction from transportation fuels and does not explicitly address water impacts, there are a number of protections already in place, as well as the sustainability provisions under development, which would minimize impact on water quality and water supply.

Leaks and spills occur occasionally and will certainly continue to occur, but the regulatory infrastructure is in place to respond to the threat posed and to enforce cleanup at the expense of the responsible party. According to the Water Board, the mostly likely cause of water pollution related to alternative fuels is leaks of fuel from underground storage tanks (UST). In terms of insurance, it should be pointed out that all owners/operators of USTs do have "insurance" to cover the cost of cleanup of leaks. They are required by statute to pay a per-gallon fee collected by the State Franchise Tax Board and paid into the State Water Board's Cleanup Fund to reimburse the cost of cleaning up fuels leaked from USTs statewide. The frequency of leaks is relatively high, but is routinely contained from release into the environment by the contemporary UST designs and, in most cases, releases are relatively easily cleaned up when releases do occur. Also, USTs are closely inspected by local agencies for tank physical integrity and compatibility of the fuel with the storage system. All UST must have Underwriter's Laboratories (UL) approval for the fuel blend stored. The discharge from biodiesel production facilities are regulated by the Regional Boards and the owner/operators of such facilities are subject to substantial fines if the discharger violates their permit of

fails to obtain a permit. In the case of spills occurring in the transporting of fuel, the risk has historically been low, but when it does occur, the hazard to the environment and human health may be acute and significant. A recent train derailment spilled three train cars of fuel grade ethanol into the Feather River causing a fish kill and threat of fire and explosion. In this case and others, the Regional Water Board with jurisdiction monitored the cleanup, which was undertaken by contractors at the expense of the railroad company. See also response to Comment F-24 regarding the applicable regulation and permitting requirements.

F-26. Comment: We support recommendations by UC researchers, which include: 1) establish water impact regulations; 2) implement a water accounting system; 3) incorporate water use efficiency and sustainability standards; 4) regulate the siting and design of biorefineries; 5) work for the incorporation of water use efficiency and sustainability standards; 6) work to ensure that California does not shift its water consumption to locales outside the state, and track the embedded water contained within feedstocks and finished fuels imported from out of state in order to assure that they are also produced in a sustainable manner; and 7) fund research to develop effective approaches to manage and minimize the negative water resource effects of California's LCFS within and without the state. (CVAQ)

Response: ARB appreciates the UC researchers' recommendations and will consider these as part of the sustainability provisions for sustainable fuels that ARB will develop during the next two years. ARB will work with other State agencies such as the State Water Board and the California Energy Commission as well as national and international organizations and academic institutions in developing its sustainability provisions. See also response to Comment F-24.

F-27. Comment: ARB identifies potentially significant impacts to water quality from biofuel spills and unlawful disposal, releases of biofuels into ground and surface water, and wastewater discharge. ARB also identifies water supply issues for the Central Valley and other water scarce areas. After identifying these significant impacts, ARB provides no information on possible mitigation measures. ARB merely states that the State Water Board has authority over water related environmental and regulatory issues, and continues by listing the possible permits that may be required for wastewater discharge. (CRPE1)

Response: ARB does not expect a greater risk or hazard to the environment or human health associated with in-state biofuel production under LCFS because the Regional Water Boards require permits to discharge to surface waters, and those permits set strict limits on the volume and concentration of substances in the discharge. The mostly likely causes of water pollution related to alternative fuels are, in descending order, estimated to be:

1. Leaks of fuel from USTs,
2. Illegal production plant discharges of wastewater or waste 'fuel',
3. Drainage from irrigated crop land, and

4. Spills occurring in the transport of fuel.

USTs are closely inspected by local agencies for tank physical integrity and compatibility of the fuel with the storage system. All UST must have UL approval for the fuel blend stored. All owner/operators of USTs are required by statute to pay a per-gallon fee collected by the State Franchise Tax Board and paid into the State Water Board's Cleanup Fund to reimburse the cost of cleaning up fuels leaked from USTs statewide. The frequency of leaks is relatively high, but is routinely contained from release into the environment by the more contemporary UST designs and, in most cases, releases are relatively easily cleaned up when releases do occur.

Runoff from agricultural land is monitored by farmer cooperatives organized by the Regional Water Boards. These co-ops collect data on pesticide and fertilizer runoff from agricultural land to detect changes in levels of toxic or harmful substances in drainage water. These data are then reported to the Regional Water Boards who in turn work with the farmers to reduce or mitigate unacceptably high levels of certain substances. Also see response to Comment F-24.

F-28. Comment: ARB should evaluate the water requirements for growing corn for ethanol and consider the potential impacts to water supply. (CAP1, CBCOC1, CERA2, CERA1, CVAQ)

Response: In general, the ethanol volume expected for LCFS compliance is comparable to what is already required under the federal RFS program (see Staff Report Appendix E). However, in California, there is a greater emphasis on cellulosic ethanol to achieve the target LCFS carbon intensity reductions. In California, there is virtually no corn grown to produce ethanol. Therefore, the water supply impact of biofuel production is expected to be less significant than in other locations in the United States or the world, where corn grown for ethanol production is a major commodity, and the water demands for irrigation, if necessary, could have a water supply impact. ARB recognizes that the water use impacts of corn grown for ethanol production and other crop-based feedstocks for biofuel production may produce water supply impacts on a national and international level. Appendix F12 of the Staff Report provides a qualitative analysis of the water impacts of 17 fuel scenarios, including producing ethanol from corn, with consideration of irrigation water volume. Chapters IV and VII of the Staff Report address broader issues associated with the water supply impacts of corn to ethanol biofuel production. See response to Comment F-24.

F-29. Comment: ARB should consider the water supply demands of biorefinery plants that may be needed for LCFS implementation. (CERA2, CERA1, CVAQ)

Response: The Staff Report addresses water supply demands of biorefinery plants associated with implementation of the LCFS in Chapters IV, VII and Appendix F12. As noted in Chapter VII of the Staff Report, new plants are subject to permitting requirements and CEQA provisions. Water use and consumption vary by type of biofuel and type of conversion technology. Biodiesel does not use or consume very much

water; however, alcohol fuels use and consume larger volumes of water in the production process. The Water Board encourages the use of treated wastewater to produce fuels and irrigate feedstock whenever possible. ARB Board Resolution 09-31 acknowledges that although some new California biorefineries could use amounts of water that have the potential to result in a small adverse impact, CEQA and State and Regional Water Board permitting requirements should mitigate any potential water supply impact by requiring a site-specific analysis and determination of water use. ARB will work with other state agencies such as the State Water Board and the California Energy Commission as well as national and international organizations and academic institutions in developing sustainability provisions, including water efficiency for biorefineries. See also response to Comment F-24 regarding permitting and CEQA requirements.

F-30. Comment: ARB should consider that increased biofuel production (including irrigating corn for ethanol and the water needs of biorefineries) may cause regional water supply impacts and water shortages and would compete with residential, industrial and other agricultural uses, including food production. Commenters provide numerous examples of water shortages in other parts of the country and the world and depletion of groundwater resources that may be exacerbated by biofuel production. (CERA1, CERA2)

Response: The Staff Report (Chapters IV, VII and Appendix F12) considers potential water supply impacts of increased biofuel production including irrigating corn for ethanol and the water needs of biorefineries. In addition, ARB Board Resolution 09-31 acknowledges that although some new California biorefineries could use amounts of water that have the potential to result in a small adverse impact, CEQA and State and Regional Water Board permitting requirements should mitigate any potential water supply impact by requiring a site-specific analysis and determination of water use. The Board Resolution also directs staff to develop an LCFS sustainability workplan by December 2009, including plans to further address water supply impacts of biofuel facilities. See also response to Comment F-24, and Section H (Food versus Fuel).

F-31. Comment: ARB should evaluate and address water supply impacts of increased biofuel production, on a fuel lifecycle basis, prior to implementation of the LCFS. (CERA1, CERA2)

Response: The ISOR addresses fuel lifecycle water supply impacts associated with implementation of the LCFS in Chapter IV (p. IV-43), Chapter VII (p. VII-24- VII-26) and Appendix F12. Table F12-2 identifies lifecycle water use for various fuel production pathways, including eight candidate fuels and seventeen scenarios; this table also addresses water quality issues for each of the fuel production pathways. Table VII-14 provides a worst case California water consumption estimate for various biofuels. See also response to Comment F-24.

F-32. Comment: Threats to the water supply resulting from biofuel production cannot be “offset.” (CERA1)

Response: Indeed, there is no regulatory requirement or mechanism currently in place to allow water supply “offsets” that are comparable to air pollutant emission offsets. However, new plants are subject to permitting requirements and CEQA provisions, which require estimates of water use. Although in certain locations and under current statutes there may be a potential for impacting groundwater supply, sustainability provisions for LCFS currently under development are expected to address potential water impacts of biofuel production. See also response to Comments F-24 and F-25.

F-33. Comment: Water requirements for ethanol from cellulose are large and it is not certain if efficiency will improve in the future. (CERA2, CVAQ)

Response: Tables VII-14 and F12-1 (Appendix F12) of the Staff Report estimate worst case water consumption for cellulosic ethanol production including biochemical conversion (6 gallons water/gallon fuel) and thermochemical conversion (1.5 gallons water/gallon fuel). The water requirements for cellulose to alcohol (acid or enzymatic hydrolysis) may be relatively high. Since no commercial scale facilities are in operation, water use is only estimated. As discussed previously, siting of any new biorefinery in California will need to confirm and address water availability with the Regional Water Board, as well as with the local planning agency, early in the CEQA and permitting process. Sustainability provisions for the LCFS currently under development are expected to address water efficiency of fuel production technologies. See also response to Comment F-24.

F-34. Comment: Biofuels production (crop-based) expansion into areas that are not currently irrigated for agriculture, especially into dry western areas, has the potential to dramatically affect the amount of water use in such areas. The actual impact would be especially significant where irrigation is introduced to a previously unirrigated area. (CERA2)

Response: See responses to Comments F-24 through F-33.

F-35. Comment: Our organization has several projects that demonstrate the potential of sustainably produced biofuels in California with minimal water use and without significant, or possibly any, food for fuel trade-off. (SUSCON)

Response: ARB recognizes that biofuels can be produced sustainably. ARB’s sustainability program, which is under development pursuant to ARB Board Resolution 09-31, is expected to have water use/water quality as a component. Also, ARB is coordinating with the California Energy Commission in its implementation of Assembly Bill 118, which has funds to support projects that produce alternative and renewable low carbon fuels to attain the state’s climate change policies. Also, see responses to Comments F-24 to F-29.

F-36. Comment: We are concerned that deployment of a low carbon biofuels industry does not lead to intensification of the demand for already limited water resources in the California Central Valley. (CVAQ)

Response: ARB acknowledges the concerns of the potential impact of any new biorefineries on limited water resources in the Central Valley. As discussed (in previous questions in this section), any siting of a biorefinery in the Central Valley is subject to the CEQA and permitting process, and the proponent would need to confirm water availability with the Water Board and local/county permitting authorities, as appropriate. Although most surface water in California is adjudicated, biorefinery developers can purchase water rights from existing owners and in so doing affect the use of that water. Since groundwater is not as stringently regulated, the use and consumption of water in the production of biofuels (especially alcohols) will be addressed more fully by the State and Regional Water Boards and ARB. As discussed in previous responses, ARB's sustainability program will include water supply as a component. See also responses to Comments F-24 through F-35 and F-37 through F-40.

F-37. Comment: Here, the Staff Report acknowledges or indicates that the Proposed Regulation may have adverse effects in the areas of ... water quality (Ethanol and biodiesel blends released to surface water may increase the likelihood and degree of fish kills compared to CARB gasoline and petroleum diesel because they deplete oxygen more rapidly.) Proposed Regulation – may “adversely impact important habitat, or interfere with critical life-cycle of native species,” due to the potential for leak, spills and wastewater discharges into water resources. Nonetheless, the Staff Report fails to evaluate any alternative to the Proposed Regulation that may avoid or lessen any of these potential impacts. (GE3)

Response: As stated in Chapter VII of the ISOR, both ARB and the Water Board are aware of the potential water quality issues associated with the projected biofuel productions. As discussed in the response to Comment F-38, ARB does not expect a greater risk to the environment with in-state biofuel production under LCFS because of the NPDES permit requirements for discharge. The effect of a release of a biofuel is generally less persistent over time than a similar release of petroleum-based fuel, which may persist for months or years, rather than days or weeks for most biofuels. See also response to Comment F-24.

F-38. Comment: The plants violated air quality regulations in 27 instances, and were cited for water pollution in even more. And ethanol is not the only culprit: a Cargill biodiesel plant in Iowa Falls prompted a fish kill after it improperly disposed of its liquid waste. The Sierra Club has already sued in Iowa and Indiana because ethanol plants have made neighbors ill from toxics in the air and the water. (CERA1)

Response: As stated in Chapter VII of the ISOR, both ARB and the Water Board are aware of the water quality concerns from biofuel production facilities and from agricultural production of transportation fuel feedstocks. ARB does not expect a greater risk or hazard to the environment or human health associated with in-state biofuel and feedstock productions under LCFS, because Regional Water Boards will not issue permits to discharge to surface waters if any local Total Daily Maximum Loading limits

will be exceeded. Please see Comment F-24 regarding the regulatory and permitting requirements.

F-39. Comment: "With the exception of wastewater from pyrolysis operations that may be highly toxic, most wastewater discharges from the proposed LCFS facilities are not expected to be 'toxic' per se, but may be high in salinity and BOD and therefore prohibited from discharge to land or water. In some cases the limitations on water discharge from production facilities may limit the development of the LCFS options in California." "Not expected to" means that ARB has not completed the requisite analysis, and the LCFS is not ripe for approval. There are two additional steps required in converting lignin and cellulose into starch, and these operations could produce wastewater streams that are high in BOD and would require on-site treatment or treatment at publicly-owned treatment works. (CERA1, CERA2)

Response: Biological Oxygen Demand (BOD) impact on surface waters is a serious concern of the State Water Board. Salinity is a major water quality issue in California; consequently any discharge that contributes significantly to salinity is highly regulated and monitored. ARB does not expect water salinity and BOD issues associated with the proposed in state LCFS production will occur because permits to discharge to surface waters will not be issued if any local Total Daily Maximum Loading limits will be exceeded. Regarding treatment of wastewater from hydrolysis of cellulose to starch and sugar at publicly owned treatment plants, the owner/operators of publicly owned treatment plants will refuse to treat any waste stream that may cause them to be in violation of their NPDES permit. Publicly owned treatment facilities are not obligated to accept industrial wastes for treatment. The wastes from hydrolysis of cellulose must be treated onsite by the owners of the cellulose conversion plant if the local public treatment facilities refuse to treat the waste stream. The Regional Water Board will require that facility to meet NPDES permit requirements. See also Comment F-24 regarding the regulatory and permitting requirements that are applicable to high salinity and BOD in discharges.

F-40. Comment: Diverting millions of gallons of water from California farms to ethanol will also add to the problem of pesticide and fossil fuel fertilizer run-off polluting our waterways. Expansion of corn on marginal lands or soils that do not hold nutrients can increase loads of both nutrients and sediments. The large recent increases in U.S. corn acreage have already led to increased rates of nitrogen [N] and phosphorous [P] loading into surface and ground waters. If projected future increases in use of corn for ethanol production do occur, the increase in harm to water quality could be considerable.

Fertilizers applied to increase agriculture yields can result in excess nutrients (nitrogen [N] and to a lesser extent, phosphorous [P]) flowing into waterways via surface runoff and infiltration to groundwater. Nutrient pollution can have significant impacts on water quality. Excess nitrogen in the Mississippi River system is known to be a major cause of the oxygen starved "dead zone" ... Corn,

soybeans, and other biomass feedstocks differ in current or proposed rates of application of fertilizers and pesticides. One metric that can be used to compare water quality impacts of various crops are the inputs of fertilizers and pesticides per unit of the net energy gain captured in a biofuel. Per unit of energy gained, biodiesel requires just 2 percent of the N and 8 percent of the P needed for corn ethanol. Pesticide use differs similarly. Low-input, high-diversity prairie biomass and other native species would also compare favorably relative to corn using this metric. ... regionally the highest stream concentrations occur where the rates of application are highest, and that these rates are highest in the U.S. "Corn Belt." These stream flows of nitrate mainly represent application to corn, which is already the major source of total N loading to the Mississippi River."

All else being equal, the conversion of other crops or non-crop plants to corn will likely lead to much higher application rates of nitrogen. Given the correlation of nitrogen application rates to stream concentrations of total nitrogen, and of the latter to the increase in hypoxia in the nation's water bodies, the potential for additional corn-based ethanol production to increase the extent of these hypoxic regions is considerable. (CERA2)

Response: We do not expect significant expansion of corn acreage in California. Currently, data on pesticide and fertilizer runoff from agricultural land is collected and monitored by farmer cooperatives organized at the direction of the Regional Water Boards to detect changes in levels of these substances in drainage water. These data are then reported to the Regional Water Boards who in turn work with the farmers to reduce or mitigate unacceptably high levels of toxic or regulated substances. See Comment F-24 regarding the regulation and permitting requirements. ARB will be developing a sustainability workplan to address sustainability issues including water quality issues both within California and elsewhere.

Mitigation of Impacts

F-41. Comment: ARB relies on future local land use decision-making processes and project-specific analysis to assess impact and mitigation measures. This is not sufficient and ARB must do an analysis of the impacts and mitigation measures before adopting the LCFS. ARB is responsible for its own legal compliance and cannot rely on another state agency to mitigate potential impacts. (CRPE1)

Response: The overall impacts are discussed in Chapter VII of the Staff Report. At this time, the number, if any, of new biofuel facilities are not known. The number and potential general locations are based on potential feedstock supply. Therefore, ARB staff conducted a thorough analysis of potential impacts based on an assessment of plausible facility developments and used the best data available to estimate the potential impacts.

As discussed in Chapter VII of the Staff Report, any impacts associated with individual projects would be assessed on a project-specific basis by the local siting authority.

Such impacts, by their nature, are more appropriately assessed on a project-specific/site-specific basis. Local agencies, rather than ARB, have the responsibility and legal authority to be the lead agencies for facility and project siting decisions. Hence, the local agencies are required by CEQA and/or NEPA to perform environmental analyses and implement all feasible mitigation measures for adverse impacts that have been identified. See also responses to Legal Authority Comments E-13 to E-20 for more on compliance with CEQA requirements.

Impacts on Agriculture

F-42. Comment: ARB lists some broad mitigation measures for conversion of farmland, but does not require that such mitigation be employed. ARB also states that conversion of agricultural land would be subject to CEQA and relies on future local decision-making processes. (CRPE1)

Response: ARB's inclusion of the GHG impacts of land use change as an element of LCFS credits should provide a direct market-driven mechanism to discourage conversion of agricultural land. Inclusion of the land use change impacts as a primary mechanism, as well as local land use protections (see Chapter VII of the Staff Report) updated with future sustainability provisions called for in Board Resolution 09-31, together should minimize the conversion of farmland. Future feedstocks for transportation fuels are expected to be from agricultural wastes, forest wastes, municipal wastes, or from crops including algae, grown on marginal land. These are not expected to have indirect land use impacts and will have the lowest carbon intensity numbers.

Impacts on Cultural Resources

F-43. Comment: ARB should specify what if any, cultural resources are likely to be affected by construction of biofuel facilities, using ARB's knowledge of current, proposed, or likely facility locations, and possible mitigation measures to address any impacts. The Staff Report identifies a possible adverse impact to cultural resources if siting, grading, facility construction or expansion occurs on lands that have not been surveyed for cultural significance. However, the Staff Report does not provide any mitigation measures and defers review to subsequent local site specific permitting. (CRPE1)

Response: As discussed in Chapter VII of the Staff Report, it is not possible to identify impacts to cultural resources associated with biofuel facility construction when the future locations are unknown. LCFS implementation is on a statewide basis without specific facility locations.

Since local agencies, rather than ARB, have the responsibility and legal authority to be the lead agencies for facility and project siting decisions, the local agencies are required by CEQA and/or NEPA to perform environmental analyses and implement all feasible mitigation measures for adverse impacts that have been identified. It is appropriate for

ARB to rely on local agencies to carry out their legal responsibilities for decisions where they are the lead agencies, especially in a programmatic document like the LCFS Staff Report, where the locations and specific characteristics of future projects are unknown at this time.

Biological Resources/Impacts on Wildlife

F-44. Comment: ARB should evaluate the biological impacts of the LCFS regulation on a statewide level based on the existing, proposed, and likely locations of biofuel production facilities. ARB has already unlawfully deferred the biological analysis to local agencies, in the Scoping Plan, and should not do so again. (CRPE1)

Response: Any potential biological impacts associated with siting of new biofuel production facilities will be assessed on a project-specific basis by the local siting authority. As discussed in Chapter VII of the Staff Report, local agencies, rather than ARB, have the responsibility and legal authority to be the lead agencies for facility and project siting decisions. Local agencies are required by CEQA and/or NEPA to consider less environmentally damaging alternatives and adopt feasible mitigation measures to reduce or avoid a project's significant impacts.

Potential environmental impacts and benefits of the LCFS regulation on a statewide basis related to biological resources are discussed in the Staff Report. Impacts to biological habitats associated with land use change resulting from growing corn for ethanol production and other crop-based biofuel production are noted. However, as cellulosic biofuel production becomes more prevalent, these impacts should decrease. Benefits to biological resources discussed in the Staff Report include fewer releases to the environment, especially waterways, from petroleum production and use because the intent of LCFS is to reduce carbon intensity compared to gasoline and diesel fuels. See also responses to Legal Authority Comments E-13 to E-20 for more on compliance with CEQA requirements.

F-45. Comment: Petroleum-based fuels have an impact on biological resources, including habitat and lifecycle interference, particularly as a result of potential releases to waters during refining, distribution and use of traditional petroleum-based fuels, as noted in the Staff Report. The LCFS indirect land use change penalty penalizes biofuels in favor of petroleum-based fuels. Hence, ARB should evaluate alternatives to the regulation that eliminate the indirect land use penalty. (GE3)

Response: The LCFS will reduce the carbon intensity of fuels in California compared with gasoline and diesel fuels. Therefore, the LCFS will decrease, not increase, petroleum fuels production or use. As discussed in Chapter VII, *Section D, Biological Resources*, p. VII-27, "Any reduction in petroleum fuel use would reduce the opportunity for [impairing important habitat or interference with critical life-cycles of native species]."

F-46. Comment: Corn-based ethanol will cause a loss of grassland and wetlands habitat including habitats for countless bird species. There are dramatic increases in the acres of marginal lands for farming in the U.S. that are being brought into corn production for the ethanol market. Large tracts of erodible land previously left as conservation easements are being brought into corn production. Ethanol use in gasoline is reversing hard-fought conservation battles that brought previously endangered wildlife in the U.S. back to healthy populations. ARB's analysis fails to consider these severe environmental impacts. (CBE3, VANDEL)

Response: The Staff Report acknowledges that production of corn ethanol and other crop-based fuels have the potential to impact wildlife habitat. The LCFS regulation discourages new land being brought into biofuel production by explicitly accounting for the greenhouse gas impact of land use change associated with food crop-based biofuels.

ARB Board Resolution 09-31, adopted on April 23, 2009, directs ARB staff to develop a workplan for sustainability provisions for the LCFS and to identify a list of biofuel feedstocks expected to have no or inherently negligible land use effects on carbon intensity. Sustainability encompasses a variety of environmental, economic, and social components, including conservation of biodiversity and wildlife protection. ARB is committed to address sustainability provisions in the LCFS within the next two years. Also, the incentivizing of fuels with low carbon intensity and lower land use impacts should reduce the impact of food crop-based fuels such as corn ethanol.

F-47. Comment: The LCFS may impact forests and sensitive ecosystems, reduce biodiversity, cause erosion, and result in the generation of massive volumes of waste water because of the inclusion of agrofuels to meet LCFS requirements. (RAN1)

Response: ARB acknowledges potential environmental impacts associated with "agrofuels," or crop-based biofuels in Chapters IV and VII of the Staff Report. The LCFS is a performance-based standard, and ARB does not specify the fuels that will be needed to achieve the carbon intensity reduction targets. Although ARB recognizes that food crop-based biofuels may be needed in the short term to meet the LCFS standard, the inclusion of land use change (LUC) in the calculation of GHG carbon intensity encourages production and use of lower carbon-intensity advanced biofuels, such as waste-derived fuels or electricity, as these fuels become more available and technologically feasible. ARB also will develop a workplan for promoting sustainability and sustainable fuels for LCFS. (See also other responses to comments regarding Biological Resources/Wildlife, Water, and Sustainability.)

Solid/Municipal Waste

F-48. Comment: Use of municipal waste as a fuel may increase toxics, criteria and other air pollutants. (CERA1)

Response: ARB supports the use of municipal solid waste and other cellulosic wastes as feedstock for fuel production because of the lifecycle reduction in carbon intensity, the reduction of land use impacts, and other environmental and sustainability benefits. However, there are safeguards in place to ensure that there will not be a net increase in criteria or toxic air pollutants associated with the siting of a new potential stationary air pollution source, including any biorefinery that would use municipal waste as a feedstock to produce alternative fuels. As discussed in Chapter VII and Appendix F3 of the Staff Report, permitting rules for siting new biorefineries in California require compliance with CEQA and with local air district requirements. Local air districts generally require Best Available Control Technology (BACT) for criteria and toxic air pollutants for commercial size facilities and pollutant offsets when BACT is not sufficient to achieve no net increase in each pollutant level. Screening analyses and health risk assessments may be performed as part of the permitting process.

The use of BACT or other more stringent air pollution control devices should address the potential for higher criteria pollutant emissions associated with acid hydrolysis conversion of municipal solid waste to ethanol. By 2020, the organic constituents in municipal waste will be used in digesters to produce biogas that can be used as CNG or LNG motor vehicle fuel or the wastes may be processed into liquid fuels. If done correctly, the production of biogas should have minimal environmental impacts. However, this and production of liquid fuels are in early stages of development and staff are directed by the Board to see that this is done right. Also, in Resolution 09-31, the Board directed staff to develop a “best practices” guidance document to assist local air districts in the permitting of new biofuel facilities.

As discussed in Chapter II of the Staff Report, the quality of alternative fuels, and motor vehicle transportation fuels, is subject to fuel specifications set by ARB as required under sections 2291.1 through 2292.7, title 13, CCR. Any new fuels derived from wastes or any other feedstock would be subject to new fuel specifications developed by ARB, as well as other state and federal fuel quality requirements.

ARB continues to evaluate existing and future conversion technologies and potential criteria, toxic and greenhouse gas air emissions as well as other environmental impacts associated with the use of municipal waste for fuel production.

F-49. Comment: Although the ARB is not presenting any default values for fuel pathways derived from municipal solid wastes for Board approval at this time, we recommend against any future approval of fuel pathways that involve combustion of 1) non-crop feedstocks (biomass wastes from municipal solid wastes, agriculture wastes, waste oils, and forestry); 2) cellulosic waste feedstock (municipal solid waste, wood waste from furniture manufacturing, and construction and demolition debris); or 3) lignocellulosic (cellulosic feedstocks (dedicated crops, crop and forest residues, or wastes) and qualifies as advanced renewable ethanol. Burning trash as fuel threatens multiple environmental and environmental justice harms, including increasing toxic and criteria pollutants and

disproportionately impacting low-income communities located near the facilities. (CERA1, CERA2)

Response: Conversion technologies including chemical techniques (such as acid hydrolysis and Fatty Acid Methyl Ester, or FAME) and thermochemical techniques are more likely pathways for the processing of biofuels than direct combustion. Other technologies that may be more promising are the digestion of wastes (including constituents from municipal wastes, livestock manure, dairy wastes, sewage sludge, and food processing wastes) to produce biogas which can be used directly as a motor vehicle fuel as CNG or LNG or can be converted to a liquid fuel using the same technology that is currently being used to convert natural gas to liquid fuels. In any case, there are environmental and environmental justice protections in place. See also response to Legal Authority Comments E-1 through E-12 for more on environmental and environmental justice protections.

F-50. Comment: The LCFS regulation should maximize opportunities and provide incentives for waste-derived fuels (especially fuels from green waste and municipal solid waste) because waste-derived fuels provide lower carbon intensity fuels and GHG benefits. Fuels from wastes are mostly produced locally, have limited transportation impacts, and do not have direct or indirect land use impacts. Other commenters indicate support for ARB's work on new lifecycle pathways for waste to alternative fuels, including biodiesel from waste sources. (APCINC, SDLAC, GDSF)

Response: ARB's intent to promote lower carbon-intensity alternative fuels is a key objective of the LCFS regulation. Waste-derived fuels have lower lifecycle carbon intensity, as pointed out by the commenters, and are, therefore, eligible to generate LCFS credits which may be sold on the open LCFS market. This is a significant incentive for waste-derived fuels under the LCFS program.

In the "30-day" modifications made available for public comment July 20, 2009, we added to the regulation lifecycle pathways and carbon-intensity values for biodiesel from used cooking oil and for renewable diesel from tallow as well as for LNG and CNG from landfill gas and from dairy digester biogas. ARB is continuing to work on new lifecycle pathways for waste to alternative fuels. Moreover, ARB Board Resolution 09-31 directed staff to work with biofuels producers and other interested stakeholders to identify specialized fuel pathways such as anaerobic digestion, thermochemical conversion of biomass feedstocks and additional liquefied natural gas pathways for incorporation into the Carbon Intensity Lookup Table.

The LCFS program also provides opportunities for regulated parties and staff to introduce new lower carbon intensity fuels such as waste-derived fuels in accordance with section 95486(c) and (d) of the regulation (methods 2A and 2B). ARB staff released a preliminary draft document entitled "Establishing New Fuel Pathways under the Low Carbon Fuel Standard", dated August 4, 2009, to provide nonbinding guidance to regulated parties on how to work with ARB to add new fuel pathways to the LCFS

Lookup Table through the rulemaking process. This draft document also provides a list of fuels “expected to have no or inherently negligible land use effects on carbon intensity,” which would allow producers of waste-derived fuels to simply report a zero land use impact on an application for a new fuel pathway with minimal additional documentation.

F-51. Comment: A major biomass source of cellulosic ethanol or fuel gas mentioned in the LCFS as a fuel pathway is waste. There should be no lowering of air quality standards for emissions from burning methane derived from dairies in engines, especially in areas such as the San Joaquin Valley. There needs to be a clear statement in the LCFS that air emission standards will not be lowered for biomethane or any other fuel or gas manufactured and/or used in the state. (AIR)

Response: It is not clear if the commenter is referring to emission standards for stationary engines used to generate electricity from dairy digesters, or to motor vehicles fueled with dairy digester gas. However, in either case, we agree that there should be no lowering of air quality emission standards. The LCFS regulation already contains a savings clause (section 95480.1(e)) which specifically provides that the LCFS does not amend, repeal, modify or change any other applicable local, State, or federal requirements. This includes the existing State fuels regulations governing specifications for CNG used in motor vehicle fuel (section 2292.5, title 13, CCR), motor vehicle emissions standards, and utilities’ CNG pipeline specifications.

Thus, the LCFS does nothing to lower the existing air quality standards for burning methane (the principal ingredient in motor vehicle CNG and LNG), in either a stationary engine or a motor vehicle engine. Any natural gas that is used to meet the LCFS requirements would also need to meet the ARB specifications for such CNG. Because of the savings clause, there is no need to add the statement requested by the commenter. But even without the savings clause, State law would require regulated parties to meet all applicable State laws and regulations, including both the LCFS (once it is in force) and existing regulations, such as section 2292.5, title 13, CCR.

F-52. Comment: If waste is being transformed into fuel or energy, ARB should consider where the waste has come from and the energy used to transport wastes over long distances. For example, sewage sludge and landfill waste is currently being transported 150 miles from the Los Angeles region into the San Fernando Valley to be dumped next to low income communities, poisoning land and ground water. ARB should consider and calculate how other alternatives, including source reduction, are more efficient than landfilling wastes. (AIR)

Response: As discussed in Appendix F of the Staff Report, facilities that convert solid waste to fuels are often located at or near the municipal waste site to take advantage of feedstock availability, thereby minimizing the transportation impact of the solid waste to fuels pathway. Also, lifecycle GHG analysis of any fuel using GREET, as discussed in Chapter IV of the Staff Report, identifies the GHG impact of each step of the fuel production process, including transportation of the feedstock to the processing facility

and processing. Although ARB's mandate is air quality and does not directly address waste management, the California Integrated Waste Management Board (CIWMB) and the Department of Toxic Substances Control (DTSC) have active solid waste and hazardous waste source reduction programs, respectively. These are key elements of California's waste management strategy and provide alternatives to landfilling the wastes. Moreover, the LCFS mandate of lower carbon intensity fuels provides support for waste-derived fuels, as discussed in the response to Comment F-50, and encourages an important alternative to landfilling. See also responses to Comments F-66 through F-86 for more on environmental justice and health risk assessment.

F-53. Comment: Waste products, such as the garbage that goes to landfills and the sewage sludge that is currently spread on farmland as a toxic soil additive cannot be converted to energy without a complete analysis, including where the byproducts end up. (AIR)

Response: The producer of any fuel is required to evaluate the lifecycle carbon intensity of the fuel using GREET, as discussed in Chapter IV of the Staff Report. The quality of alternative motor vehicle fuels, including waste-derived fuels, is subject to specific composition requirements. The specification for most fuels is set forth in sections 2291.1 through 2292.7, title 13, CCR. Any California facilities for the conversion of waste-to-fuel would also need to meet CEQA and other state and local permitting requirements. See also responses to Comments F-66 through F-86 for more on environmental justice and health risk assessment.

Hazardous Waste

F-54. Comment: ARB should assess and quantify hazardous waste impacts and should identify mitigation measures assuming that facility operators do not recycle coproducts and other hazardous materials and hazardous wastes. One commenter suggested that ARB should consider requiring biorefinery operators to recycle, reuse or reprocess hazardous materials used at their facility. (CRPE1, CERA1)

Response: The volume of hazardous wastes generated at biofuel facilities is not expected to be significant. Hazardous materials handled at biofuels facilities such as sodium hydroxide, sulfuric acid, and hexane are typical hazardous materials that are used in manufacturing operations and other businesses. Moreover, facility operators have an economic incentive not to dispose of distiller's grains and glycerol, the co-products of ethanol and biodiesel production because these have inherent economic value, as discussed in Chapter VII of the Staff Report.

Any facility that generates hazardous waste is subject to specific regulatory requirements governing the management of hazardous waste (California Health and Safety Code, Division 20, Articles 6.5, 6.8 and other related sections and California Code of Regulations, Title 22, Division 4.5). As discussed in Appendix F13 of the Staff Report, DTSC – in conjunction with local jurisdictions that have been delegated

enforcement authority – has primary responsibility for overseeing the management of hazardous materials and hazardous wastes. Hazardous waste control regulations mandate the recycling of hazardous wastes deemed to be recyclable (sections 66266.1 and 66266.2, title 22, CCR).

F-55. Comment: ARB expects that lithium automotive batteries will not be disposed of in landfills, but makes no requirement that they be recycled and has not performed any analysis of the impact of the LCFS if lithium batteries were to be disposed into landfills. (CRPE1)

Response: As discussed in Appendix F8 of the Staff Report, automotive lithium batteries are expected to be reused for other purposes after their useful life in the vehicle. After the final use, the batteries may be recycled for lithium carbonate and other metals. The recycling industry is consulting with vehicle manufacturers and is preparing for lithium ion battery recycling. Some auto manufacturers currently provide incentives such as monetary rewards or free shipment to ensure recycling of used hybrid batteries. DTSC oversees the management and disposal of hazardous wastes, and ensures enforcement of regulations that require the proper disposal and recycling of automotive lead acid batteries as well as portable rechargeable batteries (sections 66273.2, 66266.80, 66266.81, title 22, div. 4.5, CCR). Although these measures and regulations do not explicitly address lithium batteries, they are expected to serve as a model for the recycling and disposal of lithium ion batteries.

F-56. Comment: The Staff Report states “operation of new biofuel facilities will involve transportation of hazardous materials that could be released on roadways.” However, the Staff Report fails to evaluate any alternative to the proposed regulation (including elimination of the indirect land use penalty) that may avoid or lessen any of these potential impacts. (GE3)

Response: Since the volume of hazardous wastes generated at biofuel facilities is not expected to be significant, there should not be a significant increase in the amount of hazardous materials/hazardous waste transportation in California as a result of implementation of the LCFS. As discussed in Appendix F, transportation of hazardous materials and hazardous wastes are subject to strict regulatory requirements that should provide adequate safeguards against releases. In California, unless specifically exempted, it is unlawful for any person to transport hazardous wastes, unless the person holds a valid registration issued by DTSC and the shipment must be in accordance with a hazardous waste manifest. Regulatory requirements governing hazardous waste transportation in California are found in California Code of Regulations Title 22, Division 4.5, Chapter 13 and Chapter 29. All shipments of hazardous materials and hazardous wastes must be conducted in accordance with U.S. Department of Transportation requirements. The analysis of alternatives is presented in Chapter X of the ISOR and includes elimination of the consideration of indirect land use. This was rejected as an option as documented on pages X-4 and 5. See also response to Comment F-54.

Black Carbon

F-57. Comment: The LCFS does not take into account the global warming potential of black carbon, although leading researchers have found that it represents the nation's second largest GHG emission source. Our current carbon contributions from PM10, PM2.5, ultrafines, and black carbon in diesel can have the same CO2 equivalent as HFCs, resulting in artificially deflated GQI values. Additionally, black carbon is not currently included in CARB's formal list of GHGs. (GTCLLC, CBE3, SCAQMD1, CERA2)

Response: As one of the commenters has pointed out, black carbon is not on the list of greenhouse gases considered under AB32. The LCFS focused on GHGs that dominate the transportation sector, are included in AB32, and are not regulated under other regulations. These GHGs include methane, carbon dioxide, and nitrous oxide.

F-58. Comment: Black carbon has negative health impacts. As a result, the net economic benefits (including human health) of reducing black carbon emissions from diesel engines and power plants, are likely to exceed all other GHG control measures on a dollar of emission control expenditures per gram of carbon basis. (GTCLLC, CBE3, SCAQMD1, CERA2)

Response: We are aware of the negative health impacts of PM10, PM2.5, ultrafines and black carbon. These types of particles were considered during our health impacts analysis.

F-59. Comment: The LCFS will incentivize dieselization, thereby increasing black carbon. Since the LCFS doesn't take into account black carbon (a major GHG emitted by diesel combustion) dieselization of California's fuels would not only be bad for public health, but would increase this source of GHGs. (GTCLLC, CBE3, SCAQMD1, CERA2)

Response: We do not believe that the LCFS incentivizes dieselization. We have developed several scenarios that do not include the use of diesel fuel to meet the goals of the LCFS. Also, diesel fuel is subject to the same carbon intensity percent step decreases over time as gasoline.

F-60. Comment: Account for black carbon GHG emissions from diesel fuel and other sources. (CBE3)

Response: As was stated in the response to Comment F-57, the LCFS was required to reduce GHGs as identified in AB 32, which does not include black carbon. We are aware of the health impacts of black carbon and have included them in our environmental impact analysis.

Public Health Analysis

F-61. Comment: ARB has not done the analysis necessary to determine the impact of the LCFS on the environment and public health. (CON10U, CMCC, SVHCC, NFIB, CHCC1, CBE3)

Response: The LCFS ISOR does include an environmental analysis of the benefits to and impacts on a wide range of resources. Because the standard is performance-based, in which the specific pathways chosen by fuel producers are uncertain, the analysis was based on various compliance scenarios. The LCFS is expected to be environmentally beneficial in reducing GHG emissions and likely improving air quality. Potential impacts on water, agricultural resources, hazards and hazardous materials, and solid waste were also included.

The public health analysis presented in the ISOR included increased numbers of cases in each category (premature deaths, hospital admissions due to respiratory and cardiovascular causes, respiratory symptoms, work loss days, and restricted activity days) as a result of increased biofuel production facility truck traffic. An updated write-up on the public health analysis is included as Attachment A in Section B. This is the same analysis as presented to the Board in that the potential number of biorefineries, estimated truck trips, and all of the compliance scenarios (fuel volumes and feedstocks) are the same. The updated write-up does include updated heavy-duty truck emissions estimates from an updated version of EMFAC, which slightly reduced emissions and health impacts. The updated write-up clarifies the benefits of advanced vehicles, and the states that because the fuel volumes are comparable to those under the federal renewable fuels program, the majority of the biorefineries and their associated impacts would likely happen anyway in the absence of the LCFS.

In addition to the non-cancer risks outlined above, a complete health risk analysis of potential cancer risk was performed and is included in the ISOR. This analysis was completed using a worst-case scenario of three co-located biofuel production facilities.

As stated above, the ISOR included environmental and public health analysis. Going forward, the Board provided for the periodic review of the LCFS regulation, including provisions to address additional public health and air quality analyses. These provisions are presented below:

- (9) An analysis of the public health impacts of the LCFS at the state and local level, including the impacts of local infrastructure or fuel production facilities in place or under development to deliver low carbon fuels, using an ARB approved method of analysis developed in consultation with public health experts from academia and other government agencies;
- (10) An assessment of the air quality impacts on California associated with the implementation of the LCFS; whether the use of the fuel in the State will affect progress towards achieving State or federal air quality standards, or results in any significant changes in toxic air contaminant emissions; and recommendations for mitigation to address adverse air quality impacts identified;

As directed by the Board in Resolution 09-31, staff will work with local air districts, regulated parties, environmental advocates, public health experts and other stakeholders to develop a “best practices” guidance document for use by siting authorities when they are considering the siting of biofuel and other fuel production facilities in California to assess and mitigate the air quality impacts of these facilities. Development of the guidance document started with the August 5, 2009 workshop and is on-going.

F-62. Comment: The ARB should expand the public health analysis and ensure that the regulation does not contribute to elevated public health risks. (ALA1, SVHCC, ALA5, NRDC3, ABCN)

Response: The LCFS supporting documentation for the environmental analysis included an estimate of the potential cancer risk associated with potential new biorefineries and quantification of seven non-cancer health impacts associated with potential new biorefineries. These analyses were based on the best information available. In addition, as discussed in the response to Comment F-61, the Board provided for the periodic review of the LCFS regulation, including provisions to address additional public health and air quality analyses.

F-63. Comment: The LCFS should ensure that there is no impact to public health through the transport, use, or disposal of hazardous materials. (CERA1)

Response: As all active fuel-producing facilities in the state are required to comply, operators of new fuel production facilities will also be required to comply with federal, state, and local safety and environmental regulations as they relate to hazardous materials. (See also responses to Comments F-64 to F-66).

F-64. Comment: ARB should estimate the cumulative health impacts of the LCFS. (CVAQ)

Response: ARB staff conducted a cumulative health analysis to the extent data were reasonably available. The public health analysis presented in the ISOR includes increased numbers of premature deaths, hospital admissions due to respiratory and cardiovascular causes, respiratory symptoms, work loss days, and restricted activity days as a result of increased biofuel production facility truck traffic. These impacts could be offset by benefits from the 2020 vehicle fleet.

In addition to the non-cancer risks outlined above, a complete health risk analysis of potential cancer risk was performed and included in the ISOR. This analysis was completed using a worst-case scenario of three co-located biofuel production facilities. It is highly unlikely that facilities located in this manner will be successful in obtaining permits from local air districts. Even for this extreme case, the greatest impact was estimated to be an increased potential cancer risk of about 5 chances in a million.

However, this does not take into account potential benefits from reductions in emissions from the 2020 vehicle fleet.

The Board in Resolution 09-31 determined that overall the regulation is expected to result in no significant additional adverse impacts to California's statewide air quality, due to emissions of criteria and toxic pollutants; based on best available data, there may be a benefit in further reducing criteria pollutants from the 2020 vehicle fleet. The Board further acknowledged that there may be some small but potentially significant adverse impacts on a localized or regional basis from the construction and operation of biorefineries, but determined that the potential adverse impacts of the LCFS regulation are outweighed by the substantial reduction in GHG emissions and public health benefits that will result from the regulations' adoption and implementation.

Also, see response to Comment F-61.

F-65. Comment: ARB should require a comprehensive public health analysis. (SIERRA CLB3)

Response: See response to Comment F-64.

Environmental Justice and Health Risk Assessment

F-66. Comment: Biofuel production facilities will impact the communities in which they are located by releasing additional pollution. (AIR)

Response: As biofuel facilities are established in California, the safeguards in place will minimize the impact on local communities. The permitting process through local air districts requires facilities to follow New Source Review, including requirements for Best Available Control Technology and offsets. In addition, the projects will trigger CEQA review.

To provide an indication of the potential impacts, an analysis of potential cancer risk from biorefineries was performed and is included in the ISOR. This analysis was completed using a worst-case scenario of three co-located biofuel production facilities. The Board directed in Resolution 09-31 that staff prepare a "best practices" guidance document for use by siting authorities to assess and mitigate the air quality impacts of biofuel production facilities.

F-67. Comment: Also, through the LCFS implementation, environmental justice must be served so that no impacted region, such as the San Joaquin Valley, gets more air pollution, more stress on water supplies, greater build up of toxins in soils, and limited access to new jobs and new technologies. (AIR)

Response: ARB is committed to making the achievement of environmental justice an integral part of the LCFS, and to ensuring that the regulation does not disproportionately impact low-income and minority communities. (See Staff Report pp. VII-35 through

VII-37.) The Staff Report presents an analysis of potential biofuel facilities in California (see Staff Report pp. VII-8 through VII-11). The biofuel facilities are likely to be located close to available feedstocks as shown in Table VII-7 and Figure VII-1 in the Staff Report. We would expect those facilities to be located throughout California, and that no one area would be disproportionately impacted.

As discussed in Chapter VII of the ISOR, ARB staff conducted a health risk assessment (HRA) study to evaluate the local health impacts associated with toxic air contaminants emitted from typical biofuel facilities that could be built within California due to the LCFS. The assessment indicates that the increased cancer risks associated with the toxic air contaminants emissions from a biorefinery are likely to be small, and the cumulative risk from multiple biorefineries could be minimized through the permitting process.

ARB staff would like to emphasize that any new construction of biofuel facility will be subject to CEQA and air permit requirements from local air districts. Any impacts must be addressed and mitigated to the extent possible. Also, the Board in its resolution approving the LCFS committed staff to prepare a guidance document for the best practices available to reduce emissions from these types of facilities for local districts, and to monitor and participate in the CEQA and permitting processes of new facilities. As such, ARB staff believes the issues raised by the commenter will be addressed during the permitting processes.

F-68. Comment: Biorefineries create disproportionate public health risks in overburdened communities. ARB's public health analysis concluded the following, showing a disproportionate impact on the areas surrounding biorefineries. (CERA1, CBE1)

Response: As discussed in Chapter VII of the ISOR, the emissions from biofuel facilities could come from the facilities themselves and associated truck trips. We expect that emissions from the in-state biofuel facilities would be offset as a condition of permitting. The major impact is associated with the additional truck trips. On a statewide basis, these emissions may be offset by reductions in motor vehicle emissions. In the ISOR, the estimated localized diesel PM impacts are associated with these increased truck trips. As a result, the area with the greatest impact, for a worst-case analysis with three co-located facilities, has an estimated potential cancer risk of about 5 chances in a million. For perspective, the regional risk for diesel particulate in urban areas is about 500-800 potential cancers per million people over a 70-year period. For areas in close proximity to major diesel sources, such as ports, rail yards and along major transportation corridors, the increase in cancer risk from these sources alone can exceed 500 per million in some locations. Also, the increased cancer risks associated with the increased truck trips could be further minimized by CEQA and permitting decisions.

See also response to Comment F-67.

F-69. Comment: ARB staff did not address several potentially significant direct, localized, and cumulative impacts from biorefineries.

In the San Joaquin Valley, greater than 95 percent of the corn processed at biorefinery plants will be grown in the Midwest and transported by rail to the San Joaquin Valley. Kern County already bears a disproportionate burden of air pollution from numerous sources. Residents already live with pollution from a large portion of the state's oil production, hundreds of daily truck trips bringing sludge and garbage from the South Coast Region to 3 different dump sites in Kern County, and soon, floods of extra traffic relieving the Port of Oakland and LA Ports once a huge bi-modal transfer station and International Trade and Technology Center is constructed as an inland port. These cumulative impacts must be weighed when promulgating a policy that will directly encourage and incent the siting of additional sources of air pollution, particularly when counties in the Central Valley have some of the weakest local rules for emissions control than anywhere in the state. Even if the authority to site individual biorefinery plants lies with the local air district boards, the ARB must consider the direct, indirect, and cumulative effects of biorefineries upon these communities and must design the LCFS not to increase toxic and criteria air pollution as required by AB 32 law.

The Environmental Impacts analysis fails to inform decision-makers and the public about the significant and cumulative impacts – especially on environmental justice communities, and it fails to provide legally enforceable mitigation measures.

The Environmental Impacts analysis fails to inform decision-makers and the public about the significant impacts from the LCFS, it fails to provide an adequate discussion of the direct, indirect and cumulative impacts – especially on environmental justice communities, and it fails to provide legally enforceable mitigation measures. (CERA1, CERA2, CRPE1)

Response: As discussed in Chapter VII of the ISOR, staff agrees that it is important to “consider the potential for direct, indirect, and cumulative emission impacts from market-based compliance mechanisms, including localized impacts in communities that are already adversely impacted by air pollution, to design the program to prevent any increase in emissions, and maximize additional environmental and economic benefits prior to the inclusion of market-based compliance mechanisms in the regulations.”

As discussed in Chapter VII of the ISOR, staff conducted a health risk assessment study to evaluate the local cumulative health impacts associated with toxic air contaminants emitted from multiple collocated biofuel facilities within California. The result indicated that the increased risks associated with the toxic air contaminants emissions from multiple biorefineries, including the risk from associated truck trips was about 5 in a million, and could be minimized through CEQA and local permitting decisions.

Staff does not expect any cumulative impacts of LCFS on ambient ozone. On a regional and statewide basis, any increase in emissions due to biorefineries and associated truck trips could be offset by reductions in emissions from the advanced vehicle fleet, which should result in a net reduction in ozone air quality impacts. However, due to the relatively small magnitude of potential emission reductions associated with LCFS, which are much less than the ~5 percent inventory delta that is an accepted minimum for grid-based modeling to avoid numerical artifacts, it is not practical to expect the air quality model to reasonably predict the cumulative potential benefit on ozone air quality.

See also response to Comments F-67 and F-73.

F-70. Comment: The proposed LCFS regulation will disproportionately impact low-income and traditionally overburdened communities in the following ways: 1) the siting of biorefineries will disproportionately impact communities already adversely impacted by air pollution.

The ISOR correctly identifies that the federal RFS2 and the proposed LCFS regulation will substantially increase demand for biofuels in California. Therefore, there may be incentives for bringing some of the existing and permitted corn ethanol facilities back on line, as well as incentives for constructing other biofuel facilities, while some of these facilities may be proposed for construction in low-income communities.

The following is ARB Staff's only suggested strategy to address the disproportionate siting of biorefineries in low-income and traditionally disadvantaged communities: "The emissions estimated for the biofuel production facilities reflect the use of the cleanest energy conversion technologies and air pollution control technologies. ARB staff recommends that the emissions associated with the production of low carbon fuels be fully mitigated consistent with local district and CEQA requirements. To provide additional information for local districts and to inform the CEQA process, ARB staff is committed to developing a guidance document to provide information on the best practices available to reduce emissions from these types of facilities. This effort will commence immediately; ARB staff plans to have a draft available by the end of December 2009."

Members of the AB 32 EJAC attending the January 28, 2008 EJAC meeting raised the issue of local district siting agencies in the Central Valley being intentionally misled by biorefinery operators to believe that they were contributing towards global warming solutions and would fall under the LCFS when land use change estimates had barely even begun. At the meeting ARB staff suggested that they could tell the local siting agency that simply, "the LCFS is still under the regulatory process and that the GWI of fuels is still under review." When we followed-up on the suggestion in a request for a letter stating

exactly that, ARB Staff refused based upon the circular argument that “the LCFS was still under analysis.

Given that the EJAC requested a guidance document to bring to local siting agencies from ARB Staff well over a year ago, we are alarmed that staff has yet to even commence development of a guidance document, ARB’s only suggested response to address the disproportionate siting of biorefineries in low-income communities. (CERA1)

Response: Any new construction of biofuel facility will be subject to CEQA and permitting requirements. Any impacts must be addressed and mitigated to the extent possible, including impacts on disproportionately impacted communities.

In California, local agencies have the legal authority and responsibility to make local land use decisions, such as where individual facilities will be sited. Local agencies have their own regulations and ordinances that project proponents must comply with in order to obtain the necessary permits. Local agencies are usually the lead agencies for project siting decisions and are required by CEQA to perform environmental analyses and implement all feasible mitigation measures for adverse impacts that have been identified.

To provide additional information for local districts and to inform the CEQA process, the Board in its resolution approving the LCFS directed staff to prepare a guidance document for the best practices available to reduce emissions from these types of facilities for local districts, and to monitor and participate in the CEQA and permitting processes of new facilities. As such, ARB staff believes the issues raised by the commenter will be addressed during the CEQA and permitting processes. See also response to Comments F-67 and F-73.

F-71. Comment: Environmental degradation, desertification and global climate change are exacerbating destitution and desperation, especially in the highly arid countries of Saharan Africa. The IPCC has estimated that by 2050, there may be as many as 150 million 'environmental refugees' – people forced to leave their homes and lands for environmental reasons linked to global climate change, including desertification and land degradation. (CERA2)

Response: ARB acknowledges the environmental degradation, desertification and the environmental refugees issues associated with the global climate change. That is why ARB is taking the lead in implementing AB 32, the first-in-the-world comprehensive program of regulatory and market mechanisms to achieve real, quantifiable, cost-effective reductions of greenhouse gases, which includes the LCFS as one of its discrete early actions.

F-72. Comment: The proposed LCFS does not comply with requirements under CEQA. Chapter VII provides an analysis of the environmental impacts of the LCFS. This analysis is designed to comply with CEQA.

The Environmental Impacts section (Section VII) of the LCFS Staff Report and its corresponding appendix (Appendix F) inadequately address the potential environmental and environmental justice impacts of this regulation and in many instances postpone analysis until specific projects are proposed. ARB continues to forgo the opportunity to have a more exhaustive analysis of impacts and alternatives and ensure a more thorough cumulative impact analysis.

In addition, the LCFS fails to ensure that activities undertaken do not disproportionately impact low-income communities as required by AB 32. (CERA2, CRPE1)

Response: In the ISOR, the LCFS environmental impacts analyses adequately address the potential environmental and environmental justice impacts of this regulation. See response to Comments F-67, F-68, F-70, and F-73.

F-73. Comment: Also, the creation of hot spots is a danger, considering that it is a credit trading program. And the staff is proposing to allow the export of LCFS credits. (CERA2)

Response: The credit trading program and allowing the export of LCFS credits will not create any "hot-spots" issue as LCFS credits are greenhouse gas credits and the impacts of greenhouse gas emissions are global, not local. Plus LCFS credits generated are from transportation fuel use, not from specific facilities, so allowing their export should not create hot spots. And finally, although the LCFS regulation would allow the export of credits, as stated in the regulation, such export would be subject to provisions and requirements in the program importing the LCFS credits. ARB staff is not aware of the existence of any such provisions yet.

F-74. Comment: The information is available for ARB to analyze the local environmental and environmental justice impacts of the LCFS but the analysis has not been done. ARB could, and should, use the current and probable locations for facilities to look at the localized impacts. This localized analysis is important to determining what communities will be affected the most and whether the LCFS has a disproportionate impact on low-income or communities of color. (CRPE1)

Response: As discussed in Chapter VII of the ISOR, ARB staff conducted a health risk assessment study to evaluate the localized health impacts associated with toxic air contaminants emitted from typical biofuel facilities that could be built within California under LCFS. As a result, the area with the greatest impact has an estimated potential cancer risk level of over 0.4 chances in a million from the facility emissions. The risk for multiple, co-located facilities including associated off-site emissions could be 5 in a million. For perspective, the regional risk for diesel particulate in urban areas is about 500 to 800 potential cancers per million people over a 70-year period. For areas in close proximity to major diesel sources, such as ports, rail yards and along major

transportation corridors, the increase in cancer risk from these sources alone can exceed 500 per million in some locations. Also, it is anticipated that the increased cancer risks associated with the toxic air contaminants emissions from the biorefineries will be minimized by permitting and local land use decisions.

See also response to Comment F-73.

F-75. Comment: It is also important that in developing a sustainable low carbon fuel industry in California that the ARB ensure that fuel production facilities and associated transportation and processing do not degrade local environmental health or disproportionately impact vulnerable and disadvantaged communities. We therefore recommend that the LCFS contain stronger requirements for analyzing air quality and public health impacts. (CVAQ)

Response: The potential air quality and public health impacts were analyzed – see responses to Comments F-61 through F-65. Regarding potential impacts on local communities, see responses to Comments F-66 through F-70 and responses to Legal Authority Comments E-1 through E-12.

F-76. Comment: You need to ensure that we protect air quality and public health across the State, so that we don't produce fuels in neighborhoods that end up increasing pollution in those neighborhoods. (ENVCLN1)

Response: Please refer to the responses to Comments F-61 through F-70, and Legal Authority responses E-1 through E-12.

F-77. Comment: ARB suspects that many of the biorefineries built due to the LCFS will be located in the Central Valley. This is an area that has some of the worst air in the nation and already bears a disproportionate burden on air pollution from numerous sources. The communities in these areas already suffer from the pollution impacts of large confined animal facilities; facilities processing sludge, waste, and garbage from all over the state; and hundreds of daily truck trips, just to name a few. Now, these communities must bear the increased cancer risks, premature deaths, hospital admissions, and respiratory ailments that come with living near biorefineries. The siting of biorefineries across California will likely occur in low-income communities causing disproportionate impacts prohibited by the AB32 statute. For this reason alone, the proposed LCFS regulation will fail as a matter of law. (CRPE1, CERA1)

Response: We disagree that the LCFS will fail as a matter of law. See responses to Comments F-67 through F-70, and F-73 regarding why the LCFS will not result in disproportionate impacts in the Central Valley. See also responses to Legal Authority Comments E-1 through E-12 on environmental justice and AB 32 legal requirements.

F-78. Comment: Meanwhile, increasing toxic co-pollutants from existing oil and new biofuel refineries would further poison nearby low income communities of color.

In addition, the LCFS will not only result in increased facilities, but increased diesel truck and rail trips through these communities. These biorefineries will increase pollution from processing, exacerbate water shortages, and increase truck and rail transportation fueled by toxic-emitting coal and diesel, where Southern California and the San Joaquin Valley already compete for the worst air in the nation. (CBE4, CRPE1, CERA1)

Response: We disagree that the existing oil refineries and the potential new biorefineries that could be built due to the LCFS would increase pollution and further poison nearby low income communities. ARB staff expects that the emissions associated with the production of low carbon fuels in existing refineries would be mitigated consistent with local district and CEQA requirements. Also, an outcome of the LCFS is to reduce the use of conventional fossil fuels. Existing refineries will not increase throughput due to the LCFS. See also responses to Comments F-67 through F-70 and F-73.

F-79. Comment: We know that biofuels will play a significant role in order to meet the goals of this standard. And this will automatically result in building new facilities, which may get situated or built in cross proximity. Though each of those could be meeting the requirement of the permit conditions, there is a potential jointly they could be creating some problems for the nearby residents. So in order to avoid the creation of another Wilmington or some similar community, we urge the staff to issue some guidance document for best practices of the siting. And they kindly agreed and we thank the staff. And they will be bringing that item to the Board later this year or early next year. (CCA)

Response: As discussed in responses to Comments F-61 and F-64, staff analyzed worst-case potential impacts of three co-located biofuel production facilities, and determined that the greatest impact was estimated to be an increased potential cancer risk of about five chances in a million. This risk could be significantly reduced through land use planning and permitting processes.

The Board further directed ARB staff, for projects in California directly related to the production, storage, and distribution of transportation fuel subject to the LCFS, to participate in the review of specific projects; evaluate the air quality impacts of these projects; and, as appropriate, identify feasible measures to mitigate the local and regional impacts of the projects. These efforts are to be coordinated with the local air districts; lead agencies for the preparation of environmental impact reports to comply with CEQA; companies proposing to build new production, storage, and distribution facilities; and environmental and community representatives.

F-80. Comment: ARB must examine the cumulative effects on these communities before a decision on the LCFS is made. ARB Did Not Evaluate Cumulative Impacts around Biorefineries. §38570(b)(1) requires that under any market-based compliance mechanism the State Board shall "consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms

including localized impacts in communities that are already adversely impacted by air pollution." The ISOR explains that ARB staff did not do a cumulative impact analysis by ignoring the law and instead deferring it to as "the Scoping Plan is implemented and specific measures are developed, ARB and other implementing agencies will also conduct further analyses, including cumulative and multi-media impacts." The statute is clear that each and every proposed market-based compliance mechanism (note no plural) requires consideration of 1) direct, 2) indirect, and 3) cumulative emission impacts. And we feel that this is really -- you're giving up an opportunity to look at the statewide impact of this regulation. And we think it's a requirement to look at the cumulative effects of this regulation as a whole, not just on the individual facilities and individual projects that are going to come from this regulation. (CRPE1, CERA1, CRPE2)

Response: The health risk assessment conducted by staff and described in Appendix F had the effect of accounting for cumulative and localized impacts that may occur because it conservatively analyzed the impacts of three biorefineries located only 500 meters apart from each other. The UC Davis biofuel supply modeling work assumes that biorefineries to be at least 50 miles apart, since each facility would need biomass feedstock supply from that area. Therefore the three collocated biorefinery facilities represent a worst case scenario for the most conservative estimate (see response to Comments F-64 and F-70), akin perhaps to a single biorefinery facility locating near new facilities or activities of other types. See also responses to Comments E-6, E-13, and E-31 (Legal Authority).

F-81. Comment: ARB already deferred true environmental justice analysis in the AB32 Scoping Plan to subsequent rulemaking. Now, during subsequent rulemaking, ARB is again deferring any environmental justice analysis. This is unacceptable and it is time for ARB to step up and prove that it truly is "committed to making the achievement of environmental justice an integral part of the LCFS. ARB claims it already conducts "robust environmental and environmental justice assessments" of its regulatory actions. Yet, such assessments are not a part of LCFS, only promises to conduct these assessments in the future. Briefly, the -- much of the environmental analysis is deferred to project-specific review. And, in particular, with the Environmental Justice review, we think that there is enough information currently with where proposed sites might be with, you know, what types of facilities might come from this regulation to perform some analysis on the impacts of low income and minority communities; in particular, those communities that are in the Central Valley that are going to receive the greatest burden of this regulation in terms of the localized impacts. (CRPE1, CRPE2)

Response: ARB did not defer true environmental justice analysis of LCFS. See response to Comment F-67.

F-82. Comment: ARB admits that it underestimated the total public health impact of PM exposure from the LCFS (Staff Report Vol. II F-77). The assessment

excludes "estimates of the effects of PM_{2.5} on low birth weight and reduced lung function growth in children." ARB states that these effects "are significant in an assessment of the public health impacts of diesel exhaust emissions," but excludes them because the "results of the available studies are not entirely consistent." (Staff Report II F-77). Some estimate of these effects should be included in the assessment so as not to completely dismiss the importance of these effects on the public and to get a full picture of the potential health impacts of the LCFS. (CRPE1)

Response: ARB staff acknowledges that we did not quantify the effects of PM exposure on low birth weight, and reduced lung function growth in children. While these endpoints may be significant in an assessment of the public health impacts associated with exposure to diesel exhaust emissions, there are currently few published reports on these topics. Also, the results of the studies that are available are not entirely consistent. For example, estimates of the odds of low birth weight associated with PM_{2.5} exposure in two recent studies ranged from 3⁸ to 9⁹ percent and none were statistically significant. Nevertheless, there are some data supporting a relationship between PM exposure and these effects, and there is ongoing research in these areas that may clarify the role of diesel exhaust PM on these endpoints.

F-83. Comment: In addition, the public health impacts assessment completely ignores the effects on sensitive and local populations. The health impact calculations did not include biorefinery emissions because "increased local emissions from biorefineries are expected be offset by decreased emissions within the air basin." (Staff Report II F-76) It also assumes emissions are evenly distributed within the air basin (Staff Report II F-76). These assumptions ignore the impacts on local communities near existing and possible biorefinery sites. These communities, many in the Central Valley, will not reap the benefits of statewide air pollution reductions. (CRPE1)

Response: When estimating health impacts associated with a specific source in a limited geographic area, ARB uses one of two methodologies, depending on whether the pollutant concentration is estimated from modeled concentrations or from emissions data. Modeled concentrations at the local level were not available for the LCFS regulation. Due to uncertainty in the number and in the siting of potential biorefineries, and the fact that emissions will be offset within the air basin, ARB could not model the PM concentrations at the local level or determine the level of emissions. Therefore, health impacts were estimated at the air basin geographic level. For each health endpoint, we calculated the number of cases predicted to occur in each air basin. We then added up the basin-wide numbers to obtain a statewide total.

⁸1 Brauer, M; C. Lencar; L. Tamburic; M. Koehoorn; P. Demers; and K. C Karr. A Cohort Study of Traffic-Related Air Pollution Impacts on Birth Outcomes. Environmental Health Perspectives, V116N5, 2008.

⁹ Bell M.; K. Ebisu; and K. Belanger. Ambient Air Pollution and Low Birth Weight in Connecticut and Massachusetts. Environmental Health Perspectives, V115N7, 2007.

For more detail on how ARB estimates health impacts, please see “Methodology for Estimating Premature Deaths Associated with Long-term Exposure to Fine Airborne Particulate Matter in California” section G (http://www.arb.ca.gov/research/health/pm-mort/pm-mort_final.pdf). (Reference previously cited in ISOR).

Again, the Board recognized the importance of the issues raised by the commenter and directs staff to prepare a “best practices” guidance document for use by siting authorities to help local air districts in permitting such sources, to monitor and participate in the CEQA and permitting processes of new facilities, and to evaluate public health and air quality impacts of the LCFS as part of the formal periodic reviews.

F-84. Comment: The LCFS is going forward without full information on cellulosic ethanol facilities – of which ARB assumes 18 new facilities will be built as a result of the demand caused by the LCFS. While ARB admits that cellulosic facilities will have greater energy requirements than other ethanol facilities, it continues to move forward on the LCFS without fully understanding the impacts of these facilities. ARB's promise to provide a guidance document for local governments by the end of 2009 is not sufficient. First, analysis of the impacts of these facilities should not be deferred to specific projects because that leads to the type of piecemeal analysis that ARB must avoid. Second, that information is important for ARB to consider when determining the full impacts of the LCFS and whether it meets AB 32 requirements. (CRPE1)

Response: We disagree that the LCFS was approved without understanding the impacts of the cellulosic ethanol facilities. As discussed in Chapter VII of the ISOR, ARB staff conducted an HRA study to evaluate the health impacts associated with toxic air contaminants emitted from typical biofuel facilities that could be within California. In this assessment, ARB staff chose a cellulosic ethanol facility for case study, because it is more energy intensive. Furthermore, for the most conservative analysis, ARB staff even assumed 3 cellulosic ethanol facilities collocated together, which is not economical and therefore is not likely to happen. The modeled result indicated that the increased cancer risks associated with the toxic air contaminants emissions from three co-located cellulosic ethanol biorefineries are small and could be further reduced by CEQA and permitting decisions. A detailed facility impact assessment was performed as part of the rule making process of LCFS. Also see the response to Comment F-79.

F-85. Comment: ARB also inappropriately assumes there will be no increase in NOx from the use of biodiesel, despite reports showing that biodiesel increases the emissions of NOx. ARB justifies its assumption by stating that it expects to establish a specification for biodiesel to ensure there will be no increase in NOx. Given that the studies have not yet been completed, and therefore, ARB cannot be sure a zero NOx increase specification is possible, ARB should include NOx emissions from the increased use of biodiesel into its assessment. (CRPE1)

Response: As discussed in Chapter VII of the ISOR, biodiesel has been reported to increase NOx emissions compared to CARB diesel. The preliminary results from

biodiesel test program sponsored by ARB also support this finding. ARB is currently conducting an extensive test program for biodiesel and renewable diesel and will follow that effort with a rulemaking to establish biodiesel specifications to ensure there is no increase in NOx.

F-86. Comment: ARB Staff's Proposed Methods to Address Environmental Justice in the LCFS Are Incomplete. As part of ongoing AB32 analysis, ARB staff is developing a screening method for geographically representing emission densities, air quality exposure metrics, and indicators of vulnerable populations, as an evaluation aide for already adversely impacted communities. This work is not anticipated to be complete by the adoption of the LCFS. The screening method has not been developed yet, nor has ARB elaborated how such a screening tool would become enforceable when local agencies have siting authority and ARB has not even commenced work on its "Guidance Document" yet. When we asked for a letter stating that the LCFS was still under analysis, we were told no "because the LCFS was still under analysis." Now, none of ARB's offered tools to address these issues of environmental justice can guarantee that there will be no disproportionate impact on low-income populations, do not exist yet, or have not even been started. (CERA1)

Response: The screening tool for geographically representing emission densities, air quality exposure metrics, and indicators of vulnerable populations and the "Guidance Document" are both currently being developed. Also see Legal Authority responses to Comments E-1 through E-12 for related environmental and environmental justice concerns.

California Biorefineries

F-87. Comment: It will be difficult to construct biorefineries in urban areas due to the lack of emissions offsets for new sources and issues with relatively high volumes of truck traffic. (WSPA1 WEITZMAN2)

Response: We agree that finding emissions offsets for biorefinery construction in some urban areas of California is a challenge and requires diligence. Nevertheless, biorefineries have been permitted in California (see Staff Report p. VII-9 and Staff Report Volume II pp. B-50 through B-67 and response to Comment F-88 below).

F-88. Comment: Biorefinery permits will be difficult to obtain. (CSC)

Response: The most recent permitting information available reveals that there are eight proposed advanced ethanol production facilities in various stages of the permitting process. See also response to Comment F-87. To assist local air districts in the permitting process of biorefineries, ARB is in the process of preparing a siting guidance document.

F-89. Comment: To avoid an unintended worsening of air quality and threats to public health from new fuel production or fueling infrastructure, the LCFS should include requirements for state and local review to ensure that the appropriate mitigation measures are taken. (CERA3, SIERRACLB2, ALA5, CSBR3, CRPE1, NRDC3, ABCON)

Response: The ARB will assist local air districts in the permitting of biorefineries but cannot preempt their permitting authority. Local district staff can more appropriately address local air quality, local health impacts and local environmental justice issues. As directed by the Board in Resolution 09-31, a “best practices” guideline document is currently being prepared by ARB in conjunction with local air districts, regulated parties, environmental advocates, public health experts and other stakeholders. The document is intended to be used by siting authorities when considering fuel production facility locations and in the assessment and mitigation of air quality impacts.

The Board also directed staff in Resolution 09-31 to participate in the environmental review of specific projects relating to the production, storage and distribution of transportation fuels subject to the LCFS program. The review will include an evaluation of air quality impacts and feasible measures to mitigate the impacts of the projects. See also response to Legal Authority Comment E-15.

F-90. Comment: The ARB should develop guidelines for local air quality review. (ALA5)

Response: The Board, in Resolution 09-31, directed staff to prepare a “best practices” guidance document to be used by fuel production facility siting authorities. This document is currently being compiled with assistance from local air districts, regulated parties, environmental advocates, public health expert and others. This guidance document will inform users on assessment and mitigation of air quality impacts.

Adequacy of Environmental Analysis

F-91. Comment: The environmental impacts of the LCFS have not been adequately evaluated. (AB32IMPG1, CMTA, SVHCC, GE3)

Response: The analysis focuses on the significant decrease in GHG emissions that are projected to result from implementation of the program. A full fuel lifecycle analysis to determine fuel carbon intensity is complete and available to the public for 19 transportation fuels. Additionally, potential air quality impacts were estimated based on various compliance scenarios. Emissions from the production, distribution, and use of alternative fuels were included in the estimates. The air quality impacts were then analyzed for public health risks that could be associated with individual and co-located biofuel production facilities.

The scope of environmental impacts included potential impacts on water, aesthetics, agriculture, biological and cultural resources, geology and soils, hazards and hazardous

materials, mineral resources, housing and population, public services, recreation, solid waste, and transportation and traffic.

To ensure that environmental impacts of fuel production facilities are assessed and mitigated in the future, the Board directed the ARB to prepare a guidance document to set forth the best available practices to be used in siting fuel production facilities in California.

F-92. Comment: The LCFS analysis for toxic pollutant emissions is not complete. (CERA3, CERA1, ALA5)

Response: This has been done to the extent that data allows. Data on emissions of toxic pollutants from new, advanced fuel production facilities is currently limited. However, the analysis has been completed on the potential cancer health risks and the non-cancer health impacts associated with a change in exposure to PM_{2.5} emissions due to increased trucking emissions associated with the production and distribution of alternative fuels. ARB is committed to continue monitoring toxics data as it becomes available. Local air districts will, with assistance from the ARB's biorefinery siting guidelines document, consider air quality issues when permitting new fuel production facilities. See also response to Legal Authority Comments E-1 through E-12.

General

F-93. Comment: If new fuel technologies do not develop as expected, will there be an increased reliance on petroleum fuels? What are the environmental consequences if this occurs? (GE3)

Response: Because the standard is performance-based, fuel producers have the ability to choose compliance paths. The LCFS cannot result in increased reliance on petroleum fuels. The LCFS is to reduce the carbon intensity of petroleum fuels and that can only be accomplished through the use of alternative fuels. The new fuel technologies available to meet the standard are in various stages of development, and due to the diversity of promising options and the substantial research and development efforts now underway to bring the fuels to market, we conclude that compliance with the LCFS is feasible and will not result in an increased reliance on petroleum fuels. The net impact of the LCFS is to reduce reliance on petroleum fuels.

F-94. Comment: The LCFS may impact forests and sensitive ecosystems, reduce biodiversity, cause erosion, and result in the generation of massive volumes of waste water because of the inclusion of agrofuels to meet LCFS requirements. (RAN1)

Response: ARB acknowledges potential environmental impacts associated with "agrofuels," or crop-based biofuels in Chapters IV and VII of the Staff Report. The LCFS is a performance-based standard, and ARB does not specify the fuels that will be needed to achieve the carbon intensity reduction targets. Although ARB recognizes

that crop-based biofuels may be needed in the short term to meet the LCFS standard, the inclusion of land use change (LUC) in the calculation of GHG carbon intensity encourages production and use of lower carbon-intensity advanced biofuels, such as waste-derived fuels or electricity, as these fuels become more available and technologically feasible. ARB also will develop a workplan for promoting sustainability and sustainable fuels for LCFS. (See also responses to comments regarding Biological Resources/Wildlife, Water, and Sustainability.)

F-95. Comment: The environmental analysis fails to consider any of the potential environmental effects associated with the production, transportation, or use of petroleum-based fuels. (GE3)

Response: This is the baseline for the environmental analysis. Petroleum-based fuels are currently being used. The environmental analysis evaluates the incremental environmental effects associated with the production, transportation, and use of the biofuels that will be used to meet the requirements of the regulation. The LCFS will not increase the use of petroleum based fuels, but will decrease the use of these fuels.

G. SUSTAINABILITY

This section contains comments related to sustainability provisions in the LCFS. This includes the need to include such provisions in the regulation; the consideration of environmental sustainability issues, such as water, air, and land impacts; the consideration of social sustainability issues; the need to coordinate our sustainability provisions with national and international efforts; and the need to address agricultural and forestry practices.

Need for Sustainability Provisions in LCFS

G-1. Comment: The final regulation should direct ARB staff to develop metrics to ensure the LCFS provides incentives for the development of broadly sustainable alternative fuels, while avoiding unintended support for fuels with negative impacts on our forests, agricultural lands, and other important natural resources. (ABCON, NRDC3, SIERRACLB3)

Comment: It is imperative to thoroughly look at all the sustainability and economic issues. (AIR)

Comment: "Our approach is very much to only use raw materials that are produced in line with the principles of sustainable development. We oppose the destruction of rainforest and anything that undermines human rights or natural biodiversity," said President & CEO Matti Lievonen, speaking at Neste Oil's Annual General Meeting in Helsinki on March 4, 2009. (A204NES)

Comment: Ensure that the development of sustainable fuels (that avoid environmental, economic and community impacts) is incentivized. (CEERT2)

Comment: We believe the LCFS requirements for feedstock reporting, and CARB's commitment to continue developing sustainability and environmental safeguards is a critical element of the LCFS, and look forward to continued progress on those fronts. (EIN1)

Comment: There is a need for sustainability provisions to ensure that our rules don't create havoc halfway across the world. (ENVCLN1)

Comment: As CARB promotes the development of alternative fuels under the LCFS; it is critical that the environmental harms associated with reliance on fossil fuels not be traded for equally harmful impacts from expanded alternative fuel use. We therefore request that CARB put into place measures to minimize or avoid negative environmental impacts from the sourcing, production, and use of low-carbon fuels, including Impacts to air quality, species, biodiversity, wildlife habitat, soil health, water quality, water quantity, and food security. We request that CARB staff develop and present to the Board in the December 2009 amendments to the regulation, a plan for developing sustainability metrics to be

included in the LCFS regulation, with the goal of incentivizing the development of broadly sustainable alternative fuels and avoiding fuels with negative impacts on natural resources. In addition, we request that CARB assess the environmental impact of the LCFS in its periodic reviews and undertake adjustments as necessary to mitigate or avoid any identified negative impacts. (FOTE2)

Comment: Sustainability criteria will need to be developed. (SCAQMD1)

Comment: CARB should expeditiously adopt additional sustainability criteria for biofuels. Ultimately, one of the goals of the low carbon fuel standard should be to increase the use of sustainable renewable fuels, rather than simply increasing the use of renewable fuels that have greenhouse gas reduction benefits. As the use of renewable fuels increase, there is increasing public concern related to water use, land use, farming practices, and competition with the food chain associated with the use of renewable fuels. In the long term, these are all issues that need to be considered, and addressed, with regard to renewable fuels. (SHELL)

Comment: With regard to sustainability, we appreciate and support the sustainability resolution offered by staff today. As CARB promotes the development of alternative fuels under the low carbon fuel standards, it is important to ensure that this does not result in unintended negative consequences to the environment. (FOTE3)

Response: We agree that sustainability provisions are essential for the long-term success of biofuels. We are committed to working together with other State agencies, national and international organizations, non-government organizations, and other interested parties to develop an appropriate sustainability strategy for alternative fuels. This coordinated effort will be ongoing and will require the investment of time and resources over a longer timeframe.

Meanwhile, the Board directed staff in Resolution 09-31 to develop a workplan for addressing overall sustainability provisions for the LCFS; we are scheduled to present this plan to the Board in December 2009. The sustainability workplan is to include a science-based definition of sustainability; how the sustainability provisions can incent sustainable fuels; what provisions will be reviewed for inclusion in the LCFS regulation; the framework for how sustainability provisions could be incorporated and enforced in the LCFS program; and a schedule for finalizing sustainability provisions by no later than December 2011, unless the Executive Officer determines that such actions are not feasible and not appropriate. Also, please see response to comment G-7.

G-2. Comment: Please strengthen the proposed LCFS regulation by ensuring that it:

- a. results in a new generation of ultra low-carbon fuels;
- b. safeguards the ecology of sensitive ecosystems, including our federal lands and forests;

- c. promotes sustainable fuels that avoid unintended environmental and social harms, such as raising food prices; and
- d. protects California's air quality and public health. (SALVARY)

Comment: We recommend strengthening certain aspects of the regulation, as articulated in the comment letter we submitted jointly with 35 other groups on April 15. The rule should be strengthened to prevent air quality backsliding, ensure ultra-low carbon fuels are used in California, protect sensitive lands, and promote sustainable fuels production. (UCS3)

Comment: We urge the Board to approve an LCFS that reduces greenhouse gas emissions from transportation fuels without damaging California's public lands, sensitive ecosystems, water, or air quality. (SIERRACLB3)

Comment: UCS sees several opportunities to strengthen the LCFS: including minimum safeguards to ensure the LCFS does not provide unintended incentives for fuel production that result in ecological harm to our federal lands, forests, and other sensitive ecosystems; including metrics to ensure the LCFS provides incentives for the development of broadly sustainable alternative fuels, while avoiding unintended support for fuels with negative environmental or social impacts, such as raising food prices; and setting protections for California's air quality and public health. (UCS1)

Comment: CARB should ensure minimum protections for sensitive lands and ecosystems that would otherwise be incentivized by the rule for biomass production. Our study shows we do not need to sacrifice our national forests and other sensitive lands in California in order to produce biofuels. California would need only 12 percent of the forest biomass stock—using our ecological screens—to meet the needs of the LCFS under their most aggressive biofuel scenario. (NRDC3)

Response: Please see response to comment G-1. See also the “Food vs. Fuel” chapter for responses to impact on food prices and the “Environmental Impacts” chapter for responses to air quality and public health.

G-3. Comment: The biofuels standard would incentivize a rapid transition away from corn-based ethanol and toward advanced biofuels made from non-food crops. But it is also important to ensure that moving forward with low carbon fuels does not make other environmental problems worse. That is why I urge the board to adopt, as part of the LCFS, strong safeguards to protect California's public lands and sensitive ecosystems, and to develop sustainability metrics that encourage broadly sustainable biofuels. The board also must consider emissions from using biofuels that consume land where food can be grown by including an "indirect land use change" emission factor. (FORMLETTER3)

Response: As currently designed, the LCFS does promote sustainable fuel production methods which reduce land use change emissions. Fuel produced from feedstock that can be verifiably linked to biomass grown on previously marginal or degraded lands will be assessed separately using Methods 2A and 2B and receive a land use carbon intensity that more accurately reflects the direct use of marginal lands. Please see comments and responses regarding indirect land use change in the section entitled “Land Use Change,” especially the response to Comment L-86. Also, please see the response to comment G-1 for ARB’s commitment to consider sustainability provisions for inclusion in the LCFS by December 2011.

G-4. Comment: It is our fear that, if either the indirect effects of biofuels are not included in the regulation, or there are delays in their inclusion, the LCFS could perversely lead to an increase rather than a decrease in global warming pollution from transportation fuels. In this regard the regulation should also contain provisions ensuring that significant volumes of ultra low-carbon fuels are being produced in a sustainable manner by 2020. (CVAQ)

Response: We agree that considering indirect effects is appropriate when conducting a full lifecycle analysis of biofuels, and this is why indirect effects are included. In approving the LCFS, the Board directed the Executive Officer to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and to return to the Board no later than January 1, 2011, with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. The LCFS carbon-intensity standards for 2020 will require significant volumes of ultra-low-carbon fuels, and we are committed to working together with other State agencies, national and international organizations, non-government organizations, and other interested parties to develop an appropriate sustainability strategy for the LCFS. Also, please see response to Comment G-1.

G-5. Comment: Environmental Defense Fund believes CARB must endeavor to understand and discourage any degradation of our planet’s natural resources that may be incentivized by a California LCFS. We urge CARB to work within the Interagency Forest Working group (IFWG) on these issues, and look forward to the continued opportunity to participate in the ongoing dialogue. Regardless of the final method used, the LCFS must not allow California to solve one problem (high fuel carbon intensity) by creating another (aquifer impairment, ecosystem damage, soil quality impairment, etc.) (EDF2)

Response: The Board directed staff in Resolution 09-31 to work with IFWG, appropriate state agencies, environmental advocates, regulated parties, and other interested stakeholders to present a workplan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation.

The workplan will provide a framework for how sustainability provisions could be incorporated and enforced in the LCFS program, and a schedule for finalizing

sustainability provisions by no later than December 2011, unless the Executive Officer determines that such actions are not feasible and not appropriate.

G-6. Comment: Biofuels will play a significant role in reducing the carbon intensity of California fuel, at least in the early years. It is therefore critical for CARB to put minimum land safeguards in place to protect habitat, retain ecosystems intact, and avoid the conversion of new lands to biofuels plantations. One of the most straightforward ways to accomplish this goal is for CARB to adopt the land safeguards put in place by Congress and signed into law by the Bush Administration when the Renewable Fuel Standard of 2007 (RFS) was enacted at the national level. The RFS biomass sourcing protections were carefully crafted through a broad stakeholder process to provide a minimum level of protection for wildlife habitat, natural forests, native grasslands, and important public lands, while allowing biofuels production to move forward. Minimum land safeguards do not prevent activities from occurring on these lands; rather they signal to investors that fuels grown on ecologically important lands will not receive credit under the regulation. We ask that CARB either adopt the RFS minimum land safeguards or undertake, for inclusion in December 2009 amendments, the development of safeguards that offer equivalent protections. (FOTE2)

Response: We did not put in place at this time minimum land safeguards similar to the federal RFS because we believe it would take significant, sustainable biofuel feedstocks out of the market in California, namely timber slash from federal forest lands and vegetative municipal solid waste (MSW). Congress is currently addressing this very issue on a national level, reconsidering the original “safeguards” of the RFS by including biomass from federal forests and MSW.

The Board directed staff in Resolution 09-31 to work with the Interagency Forest Work Group (IFWG), the California Natural Resources Agency, the California Energy Commission, the California Department of Forestry and Fire Protection, the United States Forest Service, the U.S. EPA, environmental advocates, regulated parties, and other stakeholders to further develop definitions and safeguards for the use of “biomass” and “renewable biomass,” and propose amendments to the LCFS regulation, if appropriate.

Also, as mentioned in the response to G-1, the Board directed staff in Resolution 09-31 to develop a sustainability workplan that would provide a framework for how sustainability provisions could be incorporated and enforced in the LCFS program by no later than December 2011, unless the Executive Officer determines that such actions are not feasible and not appropriate. With this action, we will further address land safeguards.

Do Not Adopt LCFS without Sustainability Provisions

G-7. Comment: The metrics on sustainability should be developed and incorporated into the design of the LCFS before Board adoption. To wait until after the implementation of the program to investigate sustainability issues on the local, national, and global scale would be too late to prevent some of the global effects predicted to result from the incentivization of biofuels.

Comment: In order to give "sustainability" any meaning, i.e. "development that meets the needs of the present without compromising the ability of future generations to meet their own needs," any metrics developed would need to be enforceable, including the possible exclusion of a fuel that was found to be unsustainable. To not have enforceable criteria would be a useless exercise in self-reporting for the regulated entities. When there are no enforceable criteria, it is worthy to note that these calls for sustainability criteria have been criticized as "a mechanism to provide the appearance of 'clean' fuels" and gain public support when "none of the proposals for standards or certification has been developed with the support of the local communities whose livelihoods are being directly affected by agrofuel production and who are not being consulted as to whether they wish to see their land turned into monoculture plantations for agroenergy." Because ARB has not indicated what possible metrics or prohibitions would apply, the proposed regulation either jeopardizes significant stranded investments or the entrenchment of unsustainable fuels. (CERA2)

Comment: The ISOR states that "[c]urrently, there is not enough information available to develop relevant and detailed sustainability strategy or standards, despite also identifying several potential sustainability criteria adopted in other jurisdictions. Meanwhile, relying upon "the use of a global warming intensity metric in the LCFS [as] an effective surrogate for several of the sustainability concerns," as the UC Berkeley Policy Report suggests, is clearly deficient when no lifecycle analysis metric to date has incorporated water impacts, shortage or any social impacts. Even if complete lifecycle analysis models were developed per fuel, this would be at the micro-level focusing on a single fuel's pathway in emitting GHGs alone, and would ignore the macro-environmental and social effects of pursuing and developing biofuel production. (CERA2)

Response: Sustainability metrics do not have to be fully developed before adoption of the LCFS. Sustainability, as it pertains to the LCFS, is complex. Currently, there is not enough information available to develop relevant and detailed sustainability strategies or standards. Such standards will have to: address universally accepted sustainability components, contain well-developed criteria and criteria indicators, and be verifiable. Nevertheless, we can proceed with the structure and implementation of the regulation while the sustainability issues are being considered.

The consideration of sustainability for biofuel production involves national and international coordination. The U.S. and several other governments (United Kingdom,

Germany and Netherlands) have either passed laws, proposed policies, or implemented policies for the sustainable production of biofuels. Additionally, various other government organizations have committed to developing low carbon fuel standards. These include the Northeastern and Western states, as well as the Canadian provinces of British Columbia and Ontario.

Supra-national (European Union) and international organizations (United Nations Environment Programme, Roundtable on Sustainable Biofuels, Food and Agriculture Organization of the United Nations) are also addressing sustainable biofuels production. These organizations are in the process of developing sustainability criteria, as well as certification standards that could be used to evaluate the sustainability of biomass production.

Within California, the Energy Commission is developing sustainability goals (and their associated sustainability characteristics) as part of its role in administering AB 118-funded projects. We are working together with the Energy Commission to ensure that sustainability principles developed for the LCFS and AB118 are consistent. As stated previously, ARB is committed in the short term to develop a plan to address sustainability provisions, and within two years of adoption of the LCFS will develop proposed sustainability criteria, if appropriate.

Land Use

G-8. Comment: While work progresses to define globally harmonized land use change methodologies, we believe that CARB can adopt a pragmatic approach towards addressing land use change concerns. Some steps CARB can adopt include:

- a. Encourage the development of clear, transparent, effective, participatory and comprehensive land use planning rules. More effective land use planning will enable policymakers and regulators to better understand, mitigate, and monitor carbon impacts more accurately.
- b. Engage with the biofuels sustainability roundtables, such as the Roundtable for Sustainable Biofuels. These roundtables are working on better land use management standards and practices as well as certification of these standards.
- c. Encourage adoption of better land use management by adopting a bonus/incentive program—rather than a penalty approach—for the expansion of biofuels that are not likely to have a negative land use change effect, such as biofuels produced on degraded or marginal land. (SHELL)

Comment: Promote better land management outside of the LCFS. For instance, encourage agricultural practices that will result in increased carbon capture, such as the use of certain cover-crops, and develop policies that will discourage practices resulting in deforestation, both in the United States and around the globe. (ABFA)

Comment: Equally important is the development and inclusion of screening criteria for sustainable biofuels production and use to minimize environmental and public health impacts and certification schemes to ensure that sustainability is achieved. While additional research is needed to define sustainability criteria and refine estimates of the land use change associated with biofuel development, a precautionary approach requires that the standard avoid unintended consequences that could undermine the intent of this strategy. We commend this approach and urge you to retain provisions that account for sustainability and address the potential for emissions from land use change as part of the LCFS. (MADEP)

Comment: Closer to home, marginal lands for farming in the U.S. that are being brought into corn production destined for the ethanol market are increasing so dramatically, they have resorted to taking large tracts of erodible land previously left as conservation easements into corn production. This also severely impacts wildlife in those areas. Ethanol use in gasoline is reversing hard-fought conservation battles that brought previously endangered wildlife in the U.S. back to healthy populations. (CBE3)

Comment: Global deforestation, conversion of native grasslands and shrublands, and ecosystem degradation are very real problems, with impacts on biodiversity, water security, and the welfare of indigenous peoples. These land use changes have been accelerating for decades, driven by many factors—long before the U.S. biofuel industry came on the scene. The resulting greenhouse gas emissions are huge, amounting to over 18% of total global emissions. The international community must work together with urgency and speed—through international negotiations, treaties, and financial and technical assistance—to prevent further loss of forests and ecosystems across the globe. (EESI1)

Comment: I request that the iLUC issue be set aside until solid science justifies corrective action, giving the biofuels industries sufficient time to advance their technologies and join with a wide range of collaborators to significantly increase the growth of biomass on land that is currently contaminated, misused or underused. A sustainable focus on biomass enhancement will, in turn, improve watershed, wetlands, riparian buffer zones, and wildlife habitat and nature preservers. Western Europe provides a successful example of such sustainable land use practices. (BCC1)

Response: The most critical sustainability component, land use change, is incorporated in the LCFS regulation. Because the tools for estimating land use change are few and relatively new, some stakeholders have argued that land use change impacts should be excluded from carbon intensity values pending the development of better estimation techniques. Based on our work with university researchers, however, the Board concluded that the land use impacts of crop-based biofuels are significant, and must be included in LCFS fuel carbon intensities. To exclude them would allow

fuels with carbon intensities that are similar to gasoline and diesel fuel to function as low-carbon fuels under the LCFS. This would delay the development of truly low-carbon fuels, and jeopardize the achievement of a 10 percent reduction in fuel carbon intensity by 2020.

In approving the LCFS, the Board, in Resolution 09-31, directed the Executive Officer to convene an expert workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and to return to the Board no later than January 1, 2011, with recommendations, as appropriate, on approaches to address issues identified. This workgroup will evaluate key factors that might impact the land use values for biofuels including agricultural yield improvements, co-product credits, land emission factors, food price elasticity, and other relevant factors. We will coordinate this effort with similar efforts by the United States Environmental Protection Agency (U.S. EPA), European Union, and other agencies pursuing biofuels. Also, please see section L entitled "Land Use Change."

Exclude Agrofuels

G-9. Comment: I urge CARB to adopt a precautionary approach and to exclude agrofuels from the LCFS given current evidence of serious negative impacts on forests, climate, and food security. (CAPOZ)

Comment: Also, CARB should work to encourage less overall consumption of energy, including transport fuels so that we do not continue to pursue inefficient and unsustainable alternatives, such as agrofuels, to meet our insatiable demand. (FORMLETTER6)

Comment: Securing world food security while maintaining operable global ecosystems may be one of the biggest challenges humanity faces in this century. Intensifying current industrial agriculture practices for vast toxic biofuel monocultures will lead to ecological disaster. Please heed the overwhelming evidence that agrofuels worsen climate change through further deforestation and the destruction of other ecosystems, drive food prices up, force more and more people worldwide into hunger and malnutrition, and decimate biodiversity and ecosystems. (LEEUK)

Response: The LCFS sets carbon-intensity (CI) performance standards to which transportation fuels must comply. The CI values of the alternative fuels are based on full lifecycle analyses, which take into account potential negative impacts on climate change. Please see the response to comment G-1 regarding ARB's commitment to addressing sustainability provisions in the LCFS. Also, please refer to the "Food vs. Food" chapter for responses to impacts on food prices and availability.

Social Sustainability

G-10. Comment: In some cases, large-scale, mechanized farming may displace workers and poor labor conditions are associated with some large-scale agricultural plantations. In the sugar plantations of Brazil, one labor activist warned that "the social cost of [biofuels] policy is the overexploitation of labour with an army of seasonal workers who cut one ton of sugar 'cane for 2.50 reais (1.28 dollars) in precarious conditions which have already caused the deaths of hundreds of workers. An expert in agrarian development in Rio de Janeiro warned that the growth of the ethanol industry is breathing life into "a modern-day version of the sugar plantation slave-labour past." (CERA2)

Comment: There are several accounts of persistent violations of farmworkers' rights by agribusiness in the U.S. that require consideration. (CERA2)

Comment: The Brazilian Landless Workers' Movement points out that "the current model of production for bioenergy is sustained by the same elements that have always been the cause of the oppression of our peoples" - the appropriation of land, concentration of ownership and the exploitation of the labour force. (CERA2)

Comment: "Health risks associated with the production of biomass feedstocks... are similar to those of modern agriculture, including exposure to pesticides and the operation of hazardous machinery. With regard to decentralized liquid or gaseous biofuel conversion, small-scale plants need special concern for labour safety, as hazardous or explosive materials such as methanol or methane are processed." (CERA2)

Comment: The UC Berkeley report correctly asserts that "social issues associated with sustainability are not so well captured by the LCFS." However, because many are looking to California as a leader in developing its LCFS, California will have a direct influence on several sustainability issues, and must not deflect this responsibility onto the international community while simultaneously touting its leadership role. (CERA2)

Comment: The UC Berkeley report identified that "an increase in biofuel production can lead to a consolidation of land holdings which could affect small land owners with little political power." (CERA2)

Comment: "The transition to liquid biofuels can be especially harmful to farmers who do not own their own land, and to the rural and urban poor who are net buyers of food, as they could suffer from even greater pressure on already-limited financial resources. This is one of the most significant threats associated with liquid biofuel development and calls for careful consideration by decision-makers... at their worst, biofuel programmes can result in concentration of

ownership that could drive the world's poorest farmers off their land and into deeper poverty." (CERA2)

Comment: "The poorest members of a society typically do not have official title to their land, and in some cases rely on alternative land tenure arrangements ... While global market forces unleashed by the merging of the agriculture and energy industries could lead to new and stable income streams, they could also increase marginalization of the poor and indigenous peoples and affect traditional ways of living if they end up driving small farmers without clear land titles from their land and destroying their livelihoods." (CERA2)

Comment: Land grabs for agrofuels are happening across Asia, Latin America and Africa, and often involve violence. Some 150,000 families in Argentina and 90,000 families in Paraguay have already been displaced by soya. The accelerating rate of soya expansion due to the agrofuel boom is associated with increasing frequency of evictions. In Tanzania, the UK-based Sun Biofuel Plc is having over 11,000 villagers evicted for jatropha biodiesel. In Indonesia, the Chair of the UN Permanent Forum on Indigenous Issues has warned that millions of indigenous peoples will soon become biofuel refugees. (CERA2)

Comment: Lessons must be learned from the more recent expansion of soya production across Latin America, which has contributed to the deforestation of vast swathes of the Amazonian basin and has resulted in the forcible eviction of many peasants and indigenous peoples from their lands. Then on-governmental organization FIAN International has documented the complicity of agro-industrial corporations, large landowners and security forces in forced evictions in Brazil, Colombia, Argentina, Paraguay and Indonesia... In Paraguay, where the area planted with soya has more than doubled since the 1990's... many indigenous communities do not possess land titles and have been forcibly evicted. Houses, crops and animals were burned in the community of the Tetagua Guarani, in the Primero de Marzo peasant camp and in the community of Maria Antonia. It is estimated that 350 similar cases occurred in Paraguay between 1990 and 2004. In Argentina... [v]illagers in the province of Santiago del Estero have been systematically threatened by soya agribusiness, by the paramilitaries paid to protect it, and by the state police. In the Colombian region of Chocó, communities of indigenous people and people of African descent have been evicted from their land after oil palm growing companies occupied the land. Similar cases have been recorded in Indonesia and Cameroon. (CERA2)

Comment: A rapid increase in the prices of food crops will intensify competition overland and other natural resources, including forest reserves. This will pit peasant farmers and indigenous communities of forest dwellers against massive agribusiness corporations and large investors who are already buying up large swathes of land or forcing peasants off their land. The Belgian human rights organization Human Rights Everywhere (HREV) has already documented forced evictions, the appropriation of land and other violations of human rights in the

palm oil plantations in Colombia, documenting responsibilities of all the actors along the production chain. (CERA2)

Comment: Lessons must be learned from the more recent expansion of soya production across Latin America, which has contributed to the deforestation of vast swathes of the Amazonian. Loss of irreplaceable virgin forests to agriculture accounts for 25 percent of global warming. (CERA2)

Comment: The transition to liquid biofuels can be especially harmful to farmers who do not own their own land, and to the rural and urban poor who are net buyers of food, as they could suffer from even greater pressure on already-limited financial resources. This is one of the most significant threats associated with liquid biofuel development and calls for careful consideration by decision-makers... at their worst, biofuel programmes can result in concentration of ownership that could drive the world's poorest farmers off their land and into deeper poverty. (CERA2)

Comment: These aspects of the proposed system are likely to result in undesirable outcomes such as discrimination in favor of products from foreign countries with substandard environmental or human rights policies, and against products that have other desirable environmental attributes or emanate from countries with highly developed reporting systems. (CNAES)

Response: Addressing social sustainability is essential when considering the impacts of biofuel production. As mentioned previously, this must involve international cooperation and the development of enforceable certification standards. California cannot solve these global social issues through the LCFS alone; however, ARB can actively participate in these international efforts and can establish a framework for the intelligent production of biofuels for the LCFS.

We are committed in the short term to develop a plan to address other sustainability components. Specifically, the Board directed staff in Resolution 09-31 to develop a workplan for addressing overall sustainability provisions for the LCFS; we are scheduled to present this plan to the Board in December 2009. The sustainability workplan will include a framework for how sustainability provisions could be incorporated and enforced in the LCFS program and a schedule for finalizing sustainability provisions by no later than December 2011, unless the Executive Officer determines that such actions are not feasible and not appropriate. Also, please see the response to comment G-1.

Transition to Second-Generation Ethanol

G-11. Comment: Clearly, national energy policies must promote varieties of ethanol that achieve true sustainability, starting immediately with 1) producing high volumes of low-carbon varieties of corn ethanol blended with gasoline to achieve E20 or E25 blends, 2) making mid-level blends of ethanol fuel widely available at the pump and authorized for use by the EPA and states, 3) achieving rapid and deep market penetration of mid-level blends in the existing vehicle fleet, and 4) transitioning swiftly to truly sustainable ethanol made with next-generation technologies that can use non-food feedstocks. (ICM3)

Response: The U.S. EPA regulates fuels and fuel additives by authority granted under Section 211(f) of the Clean Air Act. Currently, the U.S. EPA has restricted ethanol content in gasoline to no more than 10 percent (E10). In March, the U.S. EPA received a request to consider E15, and the request is on the public docket. There are other similar efforts taking place. For example, the State of Minnesota is advocating blends up to E20. Should U.S. EPA allow E15 or E20 fuels, the additional volume of ethanol needed to meet the federal RPS2 and the LCFS may be provided by these products, which would reduce the need for E85, the only current pathway for introducing additional ethanol into the market.

Furthermore, the California Phase 3 Reformulated Gasoline (CaRFG3) regulation also limits the ethanol content in gasoline to no more than 10 percent by volume. This regulation would have to be modified if higher ethanol levels were to be allowed.

The LCFS, by being back-loaded (i.e., modest requirements in the earlier years), is designed for a reasonable transition from conventional ethanol, such as corn ethanol, to the next generation of ethanol made from biomass and waste products.

Biofuel Production Is Not Sustainable

G-12. Comment: So called "next generation" advanced fuels from non-food plants and plant parts, including forest biomass, will not resolve these problems. All industrially produced biofuel crops from fresh biomass, edible or not, still require land, soil, water, fertilizer and other finite inputs. All biofuels based upon further expansion of unsustainable, industrial agriculture policies will intensify deforestation, toxic pollution, land conflicts with local peoples, and dependence upon fossil fuel based fertilizers worldwide. It is clear that industrial biofuels are not "renewable energy" given that soils, water, land and fertilizers are all in limited supply. (LEEUK)

Comment: I am concerned with America and California's growing ethanol industry, and the implications it has in setting a precedent for massive agricultural industrialization of the world's remaining rainforests and other natural wildlands. We concur with the growing ecological consensus that large-scale industrial production of transport fuels and other energy from plants such as corn,

sugarcane, oil palm, soya, trees, grasses, or so-called agricultural and woodland waste; threatens forests, biodiversity, food sovereignty, community-based land rights and will worsen climate change.

Earth simply cannot produce the vast quantities of biomass necessary to prolong our unsustainable lifestyles. Continuing to intensify industrial agriculture through increased agrofuel and biomass energy will doom humans, who are no longer integrated with ecosystems, to extinction by exhausting stocks of minerals, soils and clean water. By mining global ecosystems for biomass, the time scale of human extinction is shrinking with every crop harvest.

Instead, we ask you to support investment in truly clean energy technologies such as wind, solar and geothermal energy that do not involve any form of combustion. We must pursue truly clean, renewable and "zero waste" technologies immediately. And you must dramatically increase the attention given to energy efficiency and conservation. Continued human habitat, adequate to allow California and all global citizens to continue living well within the Earth's ecosystems, requires CARB to now disavow corn ethanol as a global warming strategy. (LEEUK, SHAW)

Comment: Closer to home, marginal lands for farming in the U.S. that are being brought into corn production destined for the ethanol market are increasing so dramatically, they have resorted to taking large tracts of erodible land previously left as conservation easements into corn production. This also severely impacts wildlife in those areas. Ethanol use in gasoline is reversing hard-fought conservation battles that brought previously endangered wildlife in the U.S. back to healthy populations. (CBE3)

Response: The next generation of biofuels can be produced in a sustainable fashion. Sustainability encompasses a variety of environmental, economic, and social components. These include GHG emissions, conservation of high carbon stock land, conservation of high biodiversity land, air quality, water use, water quality, soil conservation, genetically modified organisms, labor rights, (working conditions, worker rights, child labor, forced labor), land rights (displacement of indigenous people), environmental justice, food price and food security. There is considerable effort taking place today internationally to address these issues, and we are committed to be part of that effort. Also, please see the response to comment G-1 for the Board's direction to staff for considering sustainability provisions within the LCFS.

The LCFS includes the consideration of land use change by requiring the use of models that address and quantify both direct and indirect land use change effects. One of the impacts of the LCFS will be the inclusion of alternative fuels into the motor vehicle fuel pool.

Limitations on Biomass Harvesting

G-13. Comment: One important point not yet fully studied is the use of agricultural and forest residues in any large quantity. This will generally not be sustainable or energy efficient because agricultural residues must be returned directly to the soil for long term fertility to be achievable. In the carbon reduced future, fossil fuel based fertilizer will need to be phased out and the only other means of maintaining crop output is to build up and maintain organic matter in the soil and not deplete it by taking crop residues off the land. It is logical that returning crop residues to farmland is far more energy efficient than collecting, transporting and then processing it into a fuel and supplementing the farmland with other sources of nutrients. There is also the obvious fact that increasing organic matter in the soil also sequesters carbon in huge quantities. (AIR)

Comment: It should never be assumed that marginal land in places like the San Joaquin Valley can be used to grow biomass for conversion to fuel. Water, especially the brackish water at the western edge of the valley, cannot be used for any crop without making irrigated land even more useless. Removing large quantities of biomass from the forests bordering the East side of the San Joaquin Valley is not practical or sustainable either. There is a limited availability of easily removable biomass from these forests. In the end, although the forest trash needs removal through fire occasionally, to think that it can be sustainably removed for more than a few years without damaging the overall productivity of the forest is nonsense. (AIR)

Comment: Even the international body U.N. Energy warned that with second-generation technologies that rely on agricultural and forestry residues, it is important to recognize that such residues are necessary for maintaining soil and ecosystem health, and that a certain amount must remain on the ground. Logging residues are an important source of forest nutrients and help protect the soil from rain, sun, and wind, lowering the risk of erosion; agricultural residues play a similar role in farm fields. The potential for carbon sequestration in large areas would be reduced if most of this organic matter were converted into bioenergy, resulting in the re-release of the carbon into the atmosphere. Especially for second-generation fuels where the entire feedstock product (including crop residues) can be utilized, it might be difficult to convince farmers to leave a certain percentage of the harvest on the field, even more-sustainable energy crops cannot substitute for natural forests or prairies.

Thus, even second-generation biofuels run the risk of achieving little to no carbon reductions when retaining plant cover, virgin forests, and pristine savannas are the best fool-proof safeguards against global warming. (CERA2)

Comment: Rapid growth in liquid biofuel production will make substantial demands on the world's land and water resources at a time when demand for both food and forest products is also rising rapidly.

One of the greatest risks is the potential impact on land used for feedstock production and harvesting (particularly virgin land or land with high conservation value), and the associated effects on habitat, biodiversity, and water, air, and soil quality. Additionally, changes in the carbon content of soils, or in carbon stocks in forests and peat lands related to bioenergy production, might offset some or all of the GHG benefits. (CERA2)

Comment: Other potential impacts include the eutrophication of water-bodies, acidification of soils and surface waters, and ozone depletion (all of which are associated with nitrogen releases from agriculture), as well as the loss of biodiversity and its associated functions. Finally, the loss of pastoral lifestyles associated with shrinking grasslands, and the loss of feed production for domesticated and wild herbivores that depend on these lands, could have significant negative economic and social impacts. (CERA2)

Comment: Examples of multimedia impacts are described in the University of California Study, which concluded that increased biofuel production will result in adverse water and land use impacts. *University of California Study: A Low Carbon Fuel Standard for California* (“UC Study”):

- a. *Part 2: Policy Analysis*, at 74: Noting the numerous sustainability issues associated with biofuels, such as degraded air and water quality, soil erosion, loss of biodiversity, loss of wilderness and natural habitats, increased concentration of land holdings and land appropriation
- b. *Part 2: Policy Analysis*, at 75: We also recommend that the state conduct independent periodic assessments of the sustainability impacts of the LCFS policy. (WSPA1)

Response: The production of second generation biofuels from forest biomass, energy crops, and agricultural wastes can have significant ecological impacts if not conducted in an environmentally sustainable manner. Habitat, biodiversity, and water, air, and soil quality are all key issues to consider when addressing sustainability. Please see the response to comment G-1 for the Board’s direction to staff for considering sustainability provisions within the LCFS.

Regarding biofuels of the future, third-generation fuels based on algae do not have brackish water limitations and require much less land. It is these fuels that are envisioned for 2020 and beyond.

Forestry Concerns

G-14. Comment: Further, we would recommend that ARB consider the conservation of forestland as a key sustainability criterion. In evaluating the capacity for continued provision of renewable forest biomass, land placed under protection for future generations has a clear advantage. Such protection can help ensure the ongoing, sustainable productive management of forests to provide a full suite of benefits—wood, water, wildlife, and a well-balanced climate. Landowners who place part or all of their property under conservation should be accordingly rewarded for doing so. Alternatively, it will be difficult to ensure sustainability while continuing to lose thousands of forested acres to development and other uses every year. (PFT)

Comment: PFT greatly appreciates the commitment from ARB to develop clear sustainability criteria within two years of LCFS adoption. This effort is fundamental for ensuring the protection of native, productive ecosystems, habitat, wildlife, biodiversity, and water and air quality. As they relate to forest biomass, the sustainability criteria should explicitly prevent the conversion of natural or semi-natural forests to energy plantations. This would be a grossly perverse outcome of the LCFS, resulting in environmental degradation and increased GHG emissions. (PFT)

Response: We support incentives for landowners who place part or all of their property under conservation protection. To that end, the Board adopted an updated Forest Project Protocol on September 24, 2009, that opens up the voluntary offsets market to private landowners, public lands and out-of-state projects.

Furthermore, the Board directed Staff in Resolution 09-31 to work with the Interagency Forest Work Group (IFWG), the California Natural Resources Agency, the California Energy Commission, the California Department of Forestry and Fire Protection, the United States Forest Service, the U.S. EPA, environmental advocates, regulated parties, and other stakeholders to further develop definitions and safeguards for the use of “biomass” and “renewable biomass.” The protection of native, productive ecosystems, habitat, wildlife, biodiversity, and water and air quality are essential elements of this effort.

International Standards

G-15. Comment: Shell is pleased that CARB recognizes these issues and is committed to developing appropriate sustainability criteria. Shell recommends that CARB engage with groups that are already working on certification program for renewable fuels and recognize the certifications provided by such groups. Initiatives supported by Shell include: Roundtable for Sustainable Palm Oil (RSPO), Roundtable for Responsible Soy (RTRS), Better Sugarcane Initiative, and the Roundtable for Sustainable Biofuels.

Common themes for these initiatives include:

- a. Responsible business practices
- b. Responsible labor conditions
- c. Respect for land rights
- d. Responsible community relations
- e. Establishment of new plantations or operations
- f. Environmental responsibility
- g. Responsible soil and water management
- h. Biodiversity
- i. Crop protection and responsible use of chemicals (SHELL)

Comment: Global deforestation, conversion of native grasslands and shrublands, and ecosystem degradation are very real problems, with impacts on biodiversity, water security, and the welfare of indigenous peoples. These land use changes have been accelerating for decades, driven by many factors long before the U.S. biofuel industry came on the scene. The resulting greenhouse gas emissions are huge, amounting to over 18 percent of total global emissions. The international community must work together with urgency and speed through international negotiations, treaties, and financial and technical assistance to prevent further loss of forests and ecosystems across the globe. (EESI1)

Comment: Whatever regulations are adopted, California, under the California Air Resources Board's leadership, should initiate and lead an effort to work with national and international experts to 1) more fully understand the complicated links between agriculturally derived fuels in the United States and deforestation in other parts of the world; and 2) assess the best ways to mitigate deforestation and other habitat destruction across the world (as a result of biofuels production). Some research by respected labs and universities shows that biofuels production on degraded agricultural land can provide opportunities for positive land use change in emerging economies if it is done right and the proper incentives are given; this may also be true for California. (SUSCON)

Comment: Bioenergy unfortunately has achieved strong negative bias from many environmental organizations because of the ill food effects of U.S. corn crop as a biofuel feedstock and the Indonesian catastrophe of using deforested areas and peat bog destructions to plant palm plantations for biodiesel. Standards need to be adopted to prevent such practices and are being developed, most particularly by the Roundtable on Sustainable Biofuels of the Ecole Polytechnique de Lausanne. But putting a false value on land use just for Bioenergy, practically making it unmarketable, is bad energy and climate policy. (PLS)

Response: We agree and have stated that international cooperation is needed to adequately address the environmental, economic, and social sustainability of biofuel production. We are committed to working together with other State agencies, national

and international organizations, non-government organizations, and other interested parties to develop an appropriate sustainability strategy for the LCFS.

Regarding the value on land use, land use impacts of crop-based biofuels are significant and must be included in LCFS fuel carbon intensities. Per Resolution 09-31, we are convening an Expert Workgroup to assist us in refining and improving the land use and indirect effect analysis of transportation fuels. This workgroup will evaluate key factors that might impact the land use values for biofuels including agricultural yield improvements, co-product credits, land emission factors, food price elasticity, and other relevant factors.

G-16. Comment: CARB plans to seek international cooperation for development of enforceable certification standards to address the sustainability components within two years of adoption of LCFS (see page ES 25). This raises the question whether such cooperation will indeed materialize, and why LCFS is moving ahead so quickly when the other players are so far behind in the same discussion and debate. Further, why is LCFS being enforced when the ground work is not complete: Staff proposes to develop a plan for incorporating sustainability metrics into the LCFS only by December 2009 (Page ES 22), which is several months after the proposed adoption of LCFS. The adoption of standards similar to LCFS in other states and countries remains uncertain. CARB makes the unreasonable and overoptimistic assumption that "the successful implementation of an effective framework in one jurisdiction should hasten the adoption of that framework elsewhere (Page ES 29)." By doing so, CARB is oversimplifying global politics and willingness of jurisdictions to work together in a spirit of cooperation, especially in an environment of global economic and financial meltdown resulting in severe unemployment rates worldwide and the threat of a depression. (CSBR2, CSBR3)

Response: Despite current economic challenges, nations continue to dedicate their resources to mediating the impacts of climate change. International cooperation on this issue is as strong as ever, and we believe that it will remain so. We are committed to working with our international partners to develop an appropriate sustainability strategy for biofuels. See the response to comment G-7.

California Biofuel Production

G-17. Comment: California should encourage indigenous biofuel production to do its share to reduce GHG without exporting all the consequences of doing so to other locations. This is partly a matter of ethics, but the state will also have the best estimates of GHG effects for local systems. (UCD2)

Response: The market will ultimately decide where the most cost-effective biofuels will be produced in an environmentally and socially sustainable manner. To meet the proposed LCFS and the federal RFS2, new biofuel production facilities may be built in California. Based on our analysis, the volume of biofuels that might be produced in

California in 2020 could be up to 1.5 billion gallons of ethanol and 0.8 billion gallons of biodiesel. Although these volumes would not completely satisfy the LCFS requirements, they would contribute to those requirements and provide needed employment, an increased tax base for the State, and value added to the biomass used as feedstock. These benefits will be more important in rural areas of the State that are short on employment but rich in natural resources.

H. FOOD VERSUS FUEL

This section contains comments related to the impact of the LCFS on food prices and availability. This includes the impact of corn ethanol production on worldwide food resources; the need to discourage biofuel production from food-based crops; and the food vs. fuel analysis contained in the ISOR.

LCFS Will Create Food Shortages and Higher Food Prices

H-1. Comment: The LCFS will increase worldwide food shortages and increase food prices. (CBE3)

Comment: Biofuels can also displace food crops and increase food prices. (ENE)

Comment: The draft LCFS greatly adds to already severe global food shortages. (CBE3)

Comment: We are in the midst of severe worldwide food price increases and food shortages. Twenty countries have had food riots since January 2008. The production of ethanol is displacing food production, bringing marginal lands into production, and increasing greenhouse emissions through soil tillage. (CBE3)

Comment: It's also important to be sure that this rule won't have us trading one environmental problem for another. While reducing carbon emissions through increased use of ethanol and other bio-fuels, for example, we might be increasing emissions that contribute to smog; or driving up the cost of food as more and more food crops are diverted to fuel use. (CBCOC1)

Comment: Food prices will increase generating more hunger and starvation worldwide. Biofuels have forced global food prices up by 75 percent—far more than previously estimated—according to a confidential World Bank report obtained by the Guardian.

The threat of biofuels on food security will also impact subsistence farmers along with Indigenous communities in particular, such as Guatamala's Maya—the People of the Corn—who have already felt the impacts on their cultural and food staple. (CERA2)

Response: We agree that, when crop-based biofuel production increases, fuel crops generally displace food crops, resulting in upward pressure on food prices. The LCFS is a performance-based standard, designed to reduce the carbon intensity of motor vehicle fuels by ten percent by the year 2020. Under the LCFS, the carbon intensities of motor fuels must account for indirect effects, including land use change, whenever such effects have been shown to be significant. The carbon intensities of fuels produced from feedstocks that displace food crops can contain land use change

components as much as double the direct lifecycle components. Thus, the LCFS is designed to stimulate the production of lower-carbon-intensity fuels that are not crop-based, and which, therefore, induce little or no land use change or food price impacts. This category of fuels includes fuels produced from forestry, agricultural, and municipal waste streams, waste oils, and tallow, as well as electricity, natural gas, and hydrogen.

Because the LCFS is a performance-based regulation, it could also stimulate agricultural innovations capable of sustainably increasing biofuel crop yields. To the extent that biofuel crop production can increase without significantly displacing food crops, the land use change carbon intensity of crop-based biofuels will decrease. For a related discussion, please see Section F, Environmental Impacts.

Biofuel yield increases will also have to be consistent with any sustainability criteria the Board approves. Sustainability provisions are essential for the long-term success of biofuels. We are committed to working together with other State agencies, national and international organizations, non-government organizations, and other interested parties to develop an appropriate sustainability strategy for the LCFS. We are developing a strategic plan for addressing overall sustainability provisions for the LCFS and are scheduled to present this plan to the Board in December 2009.

Corn Ethanol Impact on Grain Prices

H-2. Comment: To say increased corn ethanol production has had no impact on the price of corn is simply false. Ethanol production now accounts for over 25 percent of our nation's corn crop and will likely continue to increase. While ethanol producers argue that increased production levels have no impact on the price of corn, the industry argues fervently to leave federal subsidies in place. Like the ethanol industry, livestock producers received zero government subsidies. During last year's surge in gas prices, when corn ethanol was at record production, because it was more attractive to fuel blenders, the price of corn rose from \$2 to \$8. Corn production has increased in the U.S. along with yield rates but nowhere near the amount needed to offset gap in supply. And so we certainly would urge you to take a step back, look at this number, and come back with some better science. (CACA2)

Comment: In May, Mark W. Rosegrant of the International Food Policy Research Institute, testified before the U.S. Senate on biofuels and grain prices. Rosegrant said that the ethanol scam has caused the price of corn to increase by 29 percent, rice to increase by 21 percent and wheat by 22 percent. Rosegrant estimated that if the global biofuels mandates were eliminated altogether, corn prices would drop by 20 percent, while sugar and wheat prices would drop by 11 percent and 8 percent, respectively, by 2010. Rosegrant said that "If the current biofuel expansion continues, calorie availability in developing countries is expected to grow more slowly; and the number of malnourished children is projected to increase." He continued, saying "It is therefore important to find ways to keep biofuels from worsening the food-price crisis. In the short run,

removal of ethanol blending mandates and subsidies and ethanol import tariffs, and in the United States-together with removal of policies in Europe promoting biofuels-would contribute to lower food prices." (CERA2)

Comment: On January 29, Pimentel, a professor of ecology at Cornell University who has been researching the corn ethanol issue for more than two decades, published another report on the costs of producing motor fuel from grain. His article, which has seven co-authors, appeared in the journal Human Ecology. In the article, "Food Versus Biofuels: Environmental and Economic Costs," Pimentel and his fellow researchers found that "using food and feed crops for ethanol production has brought increases in the prices of US beef, chicken, pork, eggs, breads, cereals, and milk of 10 percent to 20 percent:' It concludes "Using food crops to produce ethanol raises major nutritional and ethical concerns. Nearly 60 percent of humans in the world are currently malnourished, so the need for grains and other basic foods is critical....Growing crops for biofuel not only ignores the need to reduce natural resource consumption, but exacerbates the problem of malnourishment worldwide by turning food grain into biofuel." (CERA2)

Comment: Many studies produced over the past two years have shown the high costs of ethanol and biofuels:

- a. In May 2007, the Center for Agricultural and Rural Development at Iowa State University released a report saying the ethanol mandates have increased the food bill for every American by about \$47 per year due to grain price increases for corn, soybeans, wheat, and others. The Iowa State researchers concluded that American consumers face a "total cost of ethanol of about \$14 billion." And that figure does not include the cost of federal subsidies to corn growers or the \$0.51 per gallon tax credit to ethanol producers.
- b. October 2007, the International Monetary Fund said, "Higher biofuel demand in the United States and the European Union (EU) has not only led to higher corn and soybean prices, it has also resulted in price increases on substitution crops and increased the cost of livestock feed by providing incentives to switch away from other crops."
- c. In March 2008, a report commissioned by the Coalition for Balanced Food and Fuel Policy (a coalition based in Washington, D.C. of eight meat, dairy, and egg producers' associations), estimated that the biofuels mandates passed by Congress will cost the U.S. economy more than \$100 billion from 2006 to 2009. The report declared that "The policy favoring ethanol and other biofuels over food uses of grains and other crops acts as a regressive tax on the poor." It went on to estimate that the total cost of the U.S. biofuels mandates will total some \$32.8 billion this year, or about \$108 for every American citizen.

- d. An April 8 internal report by the World Bank found that grain prices increased by 140 percent between January 2002 and February 2008. "This increase was caused by a confluence of factors but the most important was the large increase in biofuels production in the U.S. and E.U. Without the increase in biofuels, global wheat and maize [corn] stocks would not have declined appreciably and price increases due to other factors would have been moderate. "Robert Zoellick, president of the Bank, acknowledged those facts, saying that biofuels are "no doubt a significant contributor" to high food costs. And he said that "it is clearly the case that programs in Europe and the United States that have increased biofuel production have contributed to the added demand for food."
- e. In May, the Congressional Research Service blamed recent increases in global food prices on two factors: increased grain demand for meat production, and the biofuels mandates. The agency said that the recent "rapid, 'permanent' increase in corn demand has directly sparked substantially higher corn prices to bid available supplies away from other uses—primarily livestock feed. Higher corn prices, in turn, have forced soybean, wheat, and other grain prices higher in a bidding war for available crop land."
- f. In mid-June, Kraft Foods Global sponsored a report by Keith Collins, the former chief economist for the U.S. Department of Agriculture. In his 34-page analysis of grain prices, Collins concluded the ethanol scam "may account for up to 60 percent of the increase in corn prices between 2006/07 and 2008/09."
- g. In September 2008, the International Monetary Fund estimated that 70 percent of the recent increase in corn prices was due to the ethanol scam. In a report to the United Nations, Olivier de Schutter, a Belgian academic, said "Policies aimed at promoting the use of agrofuels from feedstock, having an inflationary impact on staple foods, could only be justified under international law if very strong arguments are offered." (CERA2)

Response: The prices consumers pay for food are comprised of the costs of transportation, packaging, labor, energy, agricultural commodities, and various other costs. These costs are, in turn, influenced by such factors as climate (drought, floods, etc.), fuel prices, labor policy (minimum wage changes, tightened enforcement of immigration laws), trade policy, structural changes in the commodities market (such as the diversion of food crop land to the production of biofuel feedstocks), and other factors. The sheer number of influences on food prices makes it difficult to estimate the individual contribution of any single influence. This difficulty is compounded by the fact that many of these influences are interdependent—fuel prices affect transportation prices, as well as commodity prices (via the cost of agricultural chemicals and diesel fuel), for example. Given this complexity, it is not surprising that the estimates of the contribution of increased biofuel production to food price increases presented in this series of comments vary as much as they do.

ARB staff has not prepared an estimate of the effect of biofuel demand on food prices, nor has the Board endorsed an estimate produced by another entity. As shown in Chapter IV of the initial Statement of Reasons (pages IV-41 through IV-43), however, the Board acknowledges that biofuel demand—insofar as it results in the displacement of food crops by fuel feedstock crops—can exert a significant upward pressure on food prices. The Board has determined, however, the relatively high carbon intensities of biofuels whose feedstocks displace food crops will result in a steadily decreasing dependence on such fuels in the LCFS-regulated California fuel market (see the response to comment H-1). This transition away from corn ethanol and other crop-based biofuels would not occur in the absence of the LCFS. If the LCFS were not in place, California’s consumption of non-petroleum fuels would be governed primarily by the requirements of the Federal Renewable Fuel Standard (RFS2). The RFS2 requires production of 15 billion gallons of corn ethanol along with lesser volumes of advanced biofuels by 2015. Each State is expected to consume an amount of that production that is roughly proportional to its share of overall U.S. transportation fuel consumption. That equates to about 1.5 billion gallons of corn ethanol and 1.2 billion gallons of advanced biofuels for the California market. Under the market structure created by the LCFS, however, consumption of corn ethanol would diminish to approximately 0.3 billion gallons by about 2018 (please see the response to comment H-1). The remainder of California’s non-petroleum liquid fuel needs would be met by advanced biofuels that exert little or no influence on food prices.

The market incentives to be created under the LCFS are designed to efficiently drive a transition away from fuels that are most likely to increase food prices. Lower carbon fuels—fuels that do not significantly influence food prices tend to be lower carbon fuels—earn credits under the LCFS. For fuels with carbon intensities below the annual LCFS carbon intensity limits, the number of credits earned increases as carbon intensity decreases. Because credits can be sold, they have value to fuel providers. The existence of this credit market will ensure that California transitions as quickly and efficiently as possible from higher-carbon, crop-based fuels, to lower-carbon fuels that are not produced from feedstocks that displace food crops (please see the response to comment H-1).

LCFS Disproportionately Affects Poor

H-3. Comment: Cumulatively, increased food prices will be felt most keenly by low-income people who will no longer be able to afford basic food necessities. When biofuel production drives up commodity prices, food access is compromised for low-income food purchasers. (CERA1)

Comment: Together these along with other similar policies adopted around the world contributed to the rapid increase in agricultural commodities prices impacting poor and disadvantaged people around the world. Now, more than ever, governments need to be aware of how fuel policy linked to the use of agricultural commodities could impact the world's poor. (CVAQ)

Comment: Many studies produced over the past two years have shown the high costs of ethanol and biofuels:

- a. In late June, Oxfam, the non-profit group that fights global hunger, released a report declaring that biofuels are responsible for about 30 percent of the recent increases in global food prices, and are pushing 30 million people into poverty. Rob Bailey, Oxfam's biofuel policy adviser, summarized the report: "Rich countries' demands for more biofuels in their transport fuels are causing spiraling production and food inflation."
- b. In early July, Britain's Renewable Fuels Agency concluded, "Biofuels contribute to rising food prices that adversely affect the poorest." The report, known as the Gallagher Review, also said that demand for "[biofuels] production must avoid agricultural land that would otherwise be used for food production. This is because the displacement of existing agricultural production, due to biofuel demand, is accelerating land-use change and, if left unchecked, will reduce biodiversity and may even cause greenhouse gas emissions rather than savings. The introduction of biofuels should be significantly slowed."
- c. On July 16, the Organization for Economic Cooperation and Development (O.E.C.D.) issued its report on biofuels that concluded: "Further development and expansion of the biofuels sector will contribute to higher food prices over the medium term and to food insecurity for the most vulnerable population groups in developing countries."
- d. Also in July, the U.S.D.A., the federal agency that has long been one of the corn ethanol sector's biggest boosters, admitted that corn ethanol is driving up food prices. That's somewhat remarkable given that the agency's leaders have consistently downplayed the link. Nevertheless, in July 2008, the department released a report called "Food Security Assessment, 2007," which states very clearly that the biofuels mandates are pushing up food prices. The first page of the report says: "...the persistence of higher oil prices deepens global energy security concerns and heightens the incentives to expand production of other sources of energy including biofuels. The use of food crops for producing biofuels, growing demand for food in emerging Asian and Latin American countries, and unfavorable weather in some of the largest food-exporting countries in 2006-07 all contributed to growth in food prices in recent years." While that admission is noteworthy, the July 2008 report's importance lies with its projections about the growing numbers of people around the world who are facing food insecurity. And while the U.S.D.A. report does not correlate this increasing food insecurity with soaring ethanol production, the connections are abundantly clear: As the U.S. uses more corn to make motor fuel, there is less grain available on the market. That means higher prices. And that's a key factor for residents of poor countries

who generally spend a higher percentage of their income on food than their counterparts in the developed world. For instance, in the U.S. only about 6.5 percent of disposable income is spent on food. By contrast, in India, about 40 percent of personal disposable income is spent on food. In the Philippines, it's about 47.5 percent. In some sub-Saharan Africa, consumers spend about 50 percent of the household budget on food. And according to the U.S.D.A., "In some of the poorest countries in the region such as Madagascar, Tanzania, Sierra Leone, and Zambia, this ratio is more than 60 percent." The July 2008 U.S.D.A. report goes on saying that the number of people facing food insecurity jumped from 849 million in 2006 to 982 million in 2007. And those numbers are expected to continue rising. By 2017, the number of food-insecure people is expected to hit 1.2 billion. And, says the U.S.D.A., "short-term shocks, natural as well as economic" could make the problem even worse.

- e. On October 7, 2008, the United Nations Food and Agriculture Organization weighed into the debate with a 138-page report called "Biofuels: prospects, risks and opportunities." In the section on food, the report concludes that "Rapidly growing demand for biofuel feedstocks has contributed to higher food prices, which pose an immediate threat to the food security of poor net food buyers (in value terms) in both urban and rural areas." (CERA2)

Comment: The promotion of biofuels made from food crops disproportionately impacts low-income communities and endangers food security. Therefore, we recommend that the ARB should exclude agrofuels from the LCFS—all food crops and corn-based ethanol in particular. Finally, in recognition that “maximizing technological feasibility” and “cost-effectiveness” requires guidance, specifications, and coordination, we recommend that the ARB should promote proven zero-carbon alternatives. (CERA1)

Response: Chapter IV (pg. IV-41, “Food versus Fuel Analysis”) acknowledges the potential for biofuel production to contribute to food, livestock feed, and fiber crop price fluctuations. That acknowledgement includes a brief discussion of the impacts of such price fluctuations on the poor. With the exception of those engaged in subsistence agriculture, the poor must spend a relatively large proportion of their incomes on food. When food prices rise, many poor are not able to divert additional funds to food purchases. The result is increased hunger. A formal analysis of the relative contribution of biofuel production to food, feed, and fiber prices, however, is beyond the scope of the Initial Statement of Reasons. Agricultural commodity prices are driven by a number of other factors, including oil prices (please see the response to comment H-2). The food versus fuel discussion does make it clear, however, that the Board understands and acknowledges the full range of costs and benefits associated with fuels produced from feedstocks which displace food, feed, and fiber crops. This acknowledgement reinforces the Board’s stated intention to transition away from such fuels in favor of fuels which have little or no impact on food, feed, and fiber prices and

supplies. As described in the responses to comments H-1 and H-2, the LCFS is designed to drive this transition.

LCFS Violates AB 32

H-4. Comment: There is no evidence of any ARB staff analysis on the actual attributable fault of biofuels to increased food prices, because actual modeling has not been done. We find the absence of any meaningful food price increase analysis exhibits an astonishing callousness considering that literally, millions of lives and untold human suffering are at stake. Because increases in food prices disproportionately impacts low-income people who spend a greater percentage of their income on food, the inclusion of food crops in the LCFS will violate AB 32's unequivocal requirement that actions taken pursuant to meet AB 32 goals do *not* disproportionately impact low-income communities. Thus, the inclusion of crop-based biofuels in the LCFS violates § 38562(b)(2) of AB 32. We call upon the ARB Board to exclude or not give credit to biofuels derived from food crops. (CERA1)

Comment: Here, ARB staff correctly identifies that through the production of corn and sugarcane ethanol—"the biofuels that are expected to dominate the alternative fuels market over the next five years"—the LCFS will cause an impact on food commodity prices threatening the food security of the lowest-income some of whom live in California. Because increases in food prices disproportionately impacts low-income people who spend a greater percentage of their income on food, the inclusion of food crops in the LCFS will violate AB32's unequivocal requirement that actions taken pursuant to meet AB32 goals do *not* disproportionately impact low-income communities. (CERA1)

Comment: Thus, in order to meet AB32 statutory provisions, ARB must exclude crop-based biofuels despite, in several instances, seeming to pick it as a fuel "winner." If the LCFS gives credits for the use of food crops derived from biofuels (agrofuels), the resulting competition between the fuel use of Californians and food needs around the world will undoubtedly create a disproportionate impact on low-income Californians. Meanwhile, 4,706,130 people in California were considered to be in poverty in 2004, while CA ranked as the 15th worst state for food insecurity. The conversion of farmland for crop fuel production will directly impact these millions of Californians already in poverty by increasing food prices. (CERA1)

Response: The Board is committed to ensuring that the LCFS fully complies with all applicable provisions of the AB 32 rule—including § 38562(b)(2). The Board acknowledged, in Chapter IV of the ISOR, that the production of crop-based biofuels can exert a significant upward pressure on food prices. Unlike the Federal RFS2, the LCFS is structured to encourage the development and marketing of fuels which do not place significant upward pressure on food prices (see the response to comment H-2, above). The low-carbon fuels the LCFS is designed to incentivize are fuels which—

because they induce little or no land use change—do not compete significantly with food crops for land.. These lower-carbon fuels will steadily displace higher-carbon fuels, including those with the potential to contribute to food price increases. Thus, despite California’s obligation under the RFS2 to consume its share of nationally produced biofuels, the Board predicts that the LCFS will reduce the use of higher-carbon corn ethanol to only about 300 million gallons per year by 2018 (please see the response to Comments H-1 and H-2, above).

Exclude Agrofuels

H-5. Comment: In addition, the increased food prices will have a direct disproportionate impact on low-income people causing hunger. And for this reason alone, the EJAC recommends to exclude all biofuels—all agrofuels, I'm sorry, especially corn. (CERA3)

Comment: Thus, the inclusion of crop-based biofuels in the LCFS will create the disproportionate impact of heightened food insecurity upon low-income communities in California, in direct violation of § 38562(b)(2) of AB32. “[2007] year biofuels will take a third of America's (record) maize harvest. That affects food markets directly: fill up an SUV's fuel tank with ethanol and you have used enough maize to feed a person for a year. And it affects them indirectly, as farmers switch to maize from other crops.” State measures that encourage bioethanol production will individually and cumulatively cause these food price projections, leading to heightened hunger worldwide. By 2025 rising food prices caused by the demand for biofuels could cause as many as 600 million more people to go hungry worldwide. Thus, according to the U.N. Special Rapporteur on the right to food, “The sudden, ill-conceived, rush to convert food—such as maize, wheat, sugar and palm oil—into fuels is a recipe for disaster. There are serious risks of creating a battle between food and fuel that will leave the poor and hungry in developing countries at the mercy of rapidly rising prices for food, land and water.” “The stage is now set for direct competition for grain between the 800 million people who own automobiles, and the world's 2 billion poorest people.” In sum, the increased disproportionate impacts upon low-income communities threatening food security and economic instability must be considered in the development of the LCFS, in accordance with § 38562(b)(2) requiring that all “activities undertaken to comply with the regulations do not disproportionately impact low-income communities.” Considering the deleterious impact on the poor in California alone, we call upon the ARB Board to exclude or not give credit to biofuels derived from food crops. To do so would effectively subsidize the hunger, starvation, and political instability of millions of people worldwide. (CERA1)

Comment: When considering the inclusion of agrofuels, it is important to recognize that emissions from indirect land use change (ILUC) are a major source of escalating food prices. (RAN1)

Comment: Please heed the overwhelming evidence that agrofuels worsen climate change through further deforestation and the destruction of other ecosystems, drive food prices up, force more and more people worldwide into hunger and malnutrition, and decimate biodiversity and ecosystems. (SHAW)

Response: The complete exclusion of biofuels—even those produced from feedstocks that displace food crops—is not possible over the short term in California. As discussed in the responses to comments H-2 and H-4, above, California has an obligation under the Federal Renewable Fuels Standard to consume a proportion of nationally produced ethanol fuel. Despite that obligation, however, the consumption of fuels capable of exerting upward pressure on food prices is expected to decline steadily in California, diminishing substantially by 2018 (also covered in comments H-2, H-3 and H-4).

Biofuels Do Not Raise Food Prices

H-6. Comment: Lastly, I'd like to challenge the assumption that biofuels drive up food and feed prices and results in indirect land use change. The linkage of food versus fuel and indirect land use is a false assumption. (POET2)

Comment: With regard to the so-called “Food versus Fuel” debate, there is a growing narrative that demonstrates ethanol is not principally responsible for higher food prices despite what critics have led consumers to believe during the past 12 to 18 months. On April 8th, 2009, the Congressional Budget Office released a report, “The Impact of Ethanol Use on Food Prices and Greenhouse-Gas Emissions,” which found that increased use of ethanol accounted for less than one percent of the total 5.1 percent increase, representing only 10 to 15 percent of the total increase in food prices, between April 2007 and April 2008. This is contrasted by the effect of higher energy costs on food prices, which represents approximately 36 percent of the overall food price increase. Indeed, while energy costs have since been reduced significantly, food prices remain static at the inflated price point set to offset the earlier higher input costs of energy. Volume One of the Staff Report goes on to say that “(t)he demand for biofuel feedstocks may, however, be overwhelming a food supply system that was already overextended by weather-induced production shortfalls and surging demand from a worldwide population that is both increasing in size and affluence” (IV-43). The report assumes that an increase in demand contributes to an increase in prices and a decrease in supply. However, there is no discussion of these market forces supplying an incentive for increased ingenuity, new techniques, or increased efficiency and production. The increased demand for corn used in ethanol production provides incentives for commercial seed corn companies and other industry participants to invest in additional research for the development of new technologies. Furthermore, corn producers have been and will continue to develop new technology to achieve higher yields in response to market demand. As long as incentives remain in place, yields will continue to increase. Increased supply in the marketplace supports a decrease in price. The agriculture sector and various other sectors in the world economy continue

to go through cycles in which increased demand spurs increased productivity and efficiency. Because ARB's modeled assumptions do not include an increase in yield past 2006-08, the report assumes that the LCFS will "...potentially lead to food shortages, increasing food price volatility, and inability of the world's poorest people to purchase adequate quantities of food" (IV-41). Based on the facts presented, this hypothesis is incorrect. It is simply negligent to omit any mention or analysis of increasing yields. This demonstrates that ARB staff is either outcome biased or has failed to accurately review available data. (NCGA)

Comment: However, as seen recently, the price of agriculture commodities are only partially dependent on biofuel demand. In Q4 of 2008 we saw record production of ethanol but nonetheless corn and ethanol prices fell by 70 percent. This means that corn prices are more sensitive to oil prices than to demand from the biofuels industry. Put those two together, and the result is that as oil prices go up, commodity prices go up, corn prices go up and land use intensity goes up with it. Then we go through a period of oversupply with corresponding price reduction and land use intensity reduction. So to the extent that biofuels offset the demand for oil and put a downward pressure on gasoline price, it moderates the increase in land use intensity. (LUFT)

Response: The U.S. currently has the capacity to produce about 13 billion gallons of corn ethanol annually. Producing this volume of ethanol requires more than 30 percent of America's available corn acreage. Removing that much cropland from food and feed crop production will reduce food supplies and increase prices—independently from other influences on prices. The specific mechanisms by which the displacement of food crops by biofuel feedstocks leads to higher food prices (and land use change) is described in the responses to comments L-1 and L-17.

The 10 to 15 percent increase in food prices the Congressional Budget Office attributed to the diversion of corn to the production of ethanol can be viewed (as was done in this set of comments) as small compared to the influence of energy prices. Regardless of the role of energy prices, however, a 10 to 15 percent increase is not insignificant. Although the Board has neither attempted to estimate the influence of corn ethanol demand on food prices, nor endorsed estimates made by others (see the response to comment H-2, above), it has acknowledged that the diversion of food, livestock feed, and fiber crop land to the cultivation of biofuel feedstocks can exert an upward pressure on food prices. A 10 to 15 increase is cause for concern—especially in light of the existence of higher estimates. Rather than alleviating concern about the influence of biofuel production on food prices, figures like those released by the Congressional Budget Office confirm that those concerns are well-placed. As such, they also confirm that the emphasis of the LCFS on incentivizing the transition away from fuels that can adversely affect food prices is also well-placed.

The assertion appearing in this set of comments that ARB staff negligently omitted mention of the effect of increasing yields on commodity prices and land use change rates is incorrect. As discussed in Chapter IV of the Initial Statement of Reasons, the

role of yields is accounted for on two levels in staff's analysis. Short-term measures taken to increase yields in response to rising commodity prices are captured in the GTAP model's crop yield elasticity. Longer-term yield increases are captured in the exogenous adjustment made to the model's baseline yields. This adjustment prudently does not attempt to capture the speculative future yield increases the commenter advocates including, but any significant improvements to baseline yields can be captured in the model as they verifiably occur. More detailed discussions of staff's handling of yield improvements can be found in the land use change section under the heading, "Crop Yield Adjustments."

Food vs. Fuel Analysis in ARB Staff Report

H-7. Comment: Staff shrugs off the impact of LCFS on food prices and downplays the adverse impact by blaming it on RFS 2 on Page ES 29: "The US currently has the capacity to produce about 13 billion gallons of corn ethanol annually.....The Federal Renewable Fuels Standard, on the other hand, calls for the production of 15 billion gallons per year of corn ethanol beginning in 2015. Federal biofuel regulations rather than the LCFS, will, therefore, exert the greatest pressure on food prices." Nowhere is the economic cost or impact of higher food prices factored in. (CSBR2)

Response: The Federal Renewable Fuel Standard (RFS) is a reality. California is not at liberty to ignore the RFS as it designs and implements the LCFS (please see the responses to comments H-2, H-4, and H-5, above). As previously noted,

- (1) The Board acknowledged in Chapter IV of the Initial Statement of Reasons that the diversion of food cropland to biofuel feedstock production has the potential to exert upward pressure on food prices, and
- (2) The LCFS is designed to stimulate the production of lower-carbon, non-food-crop-based fuels. For example, in all five illustrative compliance scenarios for gasoline in the ISOR, the volume of corn ethanol drops substantially by 2018, replaced by lower-carbon-intensity (CI) ethanol, such as cellulosic ethanol.

Unlike the LCFS, the RFS allows 15 billion gallons of corn ethanol to remain in the nation's transportation fuel system. A proportion of that corn ethanol must be consumed in California. For this reason, that the RFS will exert the greatest pressure on food prices.

In light of these points, the commenter's contention that staff has 'shrugged off' and 'downplayed' the influence of the LCFS on food prices is not correct. Not only does the Initial Statement of Reasons openly discuss the influence of biofuel feedstock production on food prices, that influence is explicitly built into the GTAP land use change model. For a discussion of how the GTAP handles agricultural commodity prices, please see the responses to comments L-1 and I-17. The influence of commodity prices is explicitly reflected in food prices as the model solves for a new equilibrium across all economic sectors.

H-8. Comment: I am most certainly encouraged upon my reading of pages IV-41 through IV-43. Many of the things that I have been saying about the economic and humanitarian impacts of corn-ethanol, crop based biofuel feedstock, etc., are pretty well summed up on the aforementioned pages. It is my hope that, in the formation of the "final" version of the LCFS, that ARB staff will pay diligent heed to the things recorded on the aforementioned pages. (ALEX1)

Response: As shown by most of the responses in this section of the Final Statement of Reasons, the Board remains committed to developing a fuel supply in California that does not adversely affect food prices. The LCFS continues to be structured to transition away from higher-carbon fuels, including those that can stimulate food price increases, and toward lower carbon fuels that do not significantly impact food prices (please see the response to comment H-2, for example).

H-9. Comment: CARB's food versus fuel analysis entirely omitted the significant contribution of distiller's grains co-products from ethanol plants. These co-products greatly reduce the land use and food demand impact of corn ethanol. For example, CARB estimates that it takes 110,000 acres of corn to support a 100 million gallon per year ethanol plant. However, on a net basis, after subtracting the land use credit of distiller's grain fed to animals, we estimate that impact is closer to 33,000 acres. At 15 billion gallons per year, we estimate the area impact on U.S. cropland at about 4 percent. This number is likely to go lower with time as yields improve even beyond 2015 due to advancements in seed technology. CARB's food vs. fuel analysis should be updated to account for the contribution of feed co-products and the impact of yield improvements. (RFA1)

Comment: The ISOR poorly presents a food versus fuel analysis where the costs and benefits of a 50 million gallon ethanol plant operating in California are summarized. (RFA1)

Response: The Initial Statement of Reasons identifies some of the negative impacts of operating a 50-million-gallon-per-year corn ethanol plant in California. Included in these impacts is 36,000 acres of land conversion to grow the corn—14,000 acres of which would be in the U.S.—the release of 3.6 million metric tons of greenhouse gases due to land conversions, and a net greenhouse gas emission benefit after 19 years of production. In addition to these impacts, the conversion of agricultural land to the production of biofuel feedstocks has the potential to increase the price for food, increase food price volatility, and increase pressure on water supplies.

Co-product credits—along with all other factors included in staff's GTAP land use change analysis—are included in the summary food versus fuel analysis appearing in Chapter IV of the Initial Statement of Reasons. No factors were omitted. The commenters arrived at different land use change values than did ARB staff by selecting GTAP input values that differ from those used by staff. As discussed in various

subsections of Section L (“Land Use Change”), the Board found the values proposed by this commenter to be untenable. See, for example, the responses to the comments in the sections entitled, “Co-products and Land Use Change,” and “Crop Yield Adjustments.” In this subsection, please see the response to comment H-6 for a discussion of crop yields.

In the letter containing these comments, the commenter also maintains that staff overestimated the amount land use change associated with a given unit of increase in biofuel production. As shown in the responses to comments L-47, L-69, and L-136, however, staff’s analysis is just as likely to have underestimated as to have overestimated this relationship.

Land Use Change

H-10. Comment: Considering that we have raised the food versus fuel issue repeatedly to Staff since before the adoption of the LCFS as an EAM in May of 2007 and throughout the AB32 Scoping Plan process, we find the absence of any meaningful food price increase analysis exhibits an “astonishing callousness” considering that literally, millions of lives and untold human suffering are at stake. At the March 27, 2009, LCFS workshop, Professor Michael O’Hare at UC Berkeley stated via teleconference participation that he ran his own GTAP model and found that biofuels attributed towards 50 percent of the increased food prices in the food versus fuel debate. Mr. O’Hare expressed the opinion that he thinks the ARB should “take food price increases seriously.” If ARB’s contractor, an individual professor, was able to run an initial model on his own, we believe that ARB can run preliminary models of the attributable effect biofuels has on increased food prices considering that ARB staff already employs the GTAP model to calculate global land use change impacts. (CERA1)

Response: For reasons articulated in the response to comment H-2, above, the Board has not endorsed any current estimate of the independent contribution of increasing biofuel demand to changes in food prices. Those reasons are exemplified by the wide differential between higher-end estimates like the one cited in this comment, and more conservative estimates such as the 10-15 percent increase found by the Congressional Budget Office (please see the response to comment H-6, above).

Not endorsing a specific estimate is not the same as failing to acknowledge and act on information linking crop-based biofuel production to food prices, however. The Board explicitly acknowledged this link on pages IV-41 through IV-43 of the Initial Statement of Reasons. Short of summarily excluding crop-based biofuels from the California market—an action that would place the State in conflict with Federal law (please see the response to comment H-2, H-3, and H-4)—California has structured the LCFS to quickly and efficiently transition the state’s fuel supply away from fuels that can adversely affect food prices and toward fuels which will have little or no food price impacts. The structural elements that will accomplish this transition are described in the response to comment H-2.

I. ECONOMICS

This section contains comments related to the economic analysis conducted by ARB staff for the LCFS. This includes cost estimations for alternative fuels, crude oils, and petroleum-based fuels; the impact of the LCFS on businesses and consumers; the cost-effectiveness of the regulation; and the inherent uncertainty in the estimations and underlying assumptions of the analyses.

Crude Prices

I-1. Comment: We believe that it is more realistic that the low end of assumed crude oil prices, i.e., \$66 per barrel, should be used for the entire period through 2020. The economic analysis assumes future costs for conventional fuels that are too high, which contributes to an underestimation of the costs of LCFS fuels by over one billion dollars per year. (WSPA1)

Comment: Staff does not consider future availability of alternative fuels or any major fluctuations or disruptions in the demand supply equation leading and the resulting prices. Their sensitivity analysis based on higher crude prices also does not reflect the reality both in commodity markets as well as for crude oil experienced just during this past one year.

Table VIII-I is not reflective of the reality and current market prices we have especially seen in the last one year. Staff needs to develop better ranges that account for high levels of volatility in prices, which in turn will have a major impact on the entire economic analysis that in its current form appears oversimplified. The forecasts by Staff of prices of crude, gasoline, and diesel do not take into account the tremendous volatility and large ranges of trading prices we have experienced this past year. Staff uses 2007 IEPR estimates to be consistent with the scoping plan, but those are already outdated. The economic reality and financial markets today are suddenly very different from where we were as recently as August 2008. To rely on projections made in 2007 is not just unrealistic, but simply absurd. On Page VIII-I Staff admits that "Staff understands that the economic analysis of the LCFS is greatly affected by future oil prices and the actual production costs and timing of lower carbon intensity fuels. Economic factors, such as tight supplies of lower carbon intensity fuels or a lengthy economic downturn keeping crude demand and hence prices down, could result in overall net costs, not savings, for the LCFS." Staff has neither tried to quantify the impact of this nor take this into consideration before rushing to implement LCFS without regard for current market conditions or the ability of the California economy to absorb the economic shock associated with AB 32 and LCFS. (CSBR2, CSBR3)

Response: For the economic analysis, we used crude price estimates from the 2007 Integrated Energy Policy Report (IEPR), published by the California Energy Commission. The higher estimates in that document were \$66 - \$88/barrel (bbl) for the

time period of 2010 - 2020. The Energy Information Administration, in its Annual Energy Outlook 2009, projected crude prices to be \$78 to \$116/bbl for the same 2010 – 2020 period. We chose not to use these higher estimates, but to use the 2007 EIPR estimates of \$66 - \$88.

As presented in Table VIII-9 of ISOR, we considered the fluctuation of alternative fuel costs as crude price varies between 2010 – 2020. We cannot forecast short-term disruptions in supply or demand of petroleum-based fuels or alternative fuels caused by unforeseen world events.

We recognize the volatility in commodity prices, including crude prices: 2008 was the epitome of a volatile market. In the summer of 2008, crude prices climbed to nearly \$150/bbl, followed by a steep decline to less than \$40/bbl by year's end. In 2009, crude prices have rebounded despite a continuing worldwide economic recession. As domestic and global economies improve, the demand for oil will increase, leading to higher crude prices. We believe we used reasonable cost estimates in the economic analysis.

Ethanol Production Cost

I-2. Comment: A new study by National Renewable Energy Laboratory (NREL) states that the production cost of cellulosic ethanol at a minimum is \$5.14 per gge, which is twice the cost estimated by CARB staff at \$2.70 per gge. (WEITZMAN2, WEITZMAN1, CONOCO)

Response: We estimated the cost of production of cellulosic ethanol based on published studies by NREL, the Department of Energy (DOE), and others that were available at the time the analysis was conducted. According to the 2007 NREL State of Technology Study, the estimated cost of cellulosic ethanol production, using a feedstock of corn stover, is estimated at \$2.43 per gal (\$3.60 per gge), with a DOE target cost of \$1.33 per gal (1.97 per gge) for 2012. Based on our estimates, the cost of cellulosic ethanol for 2012 is \$1.93 per gal (\$2.86 per gge), which is conservative compared to the DOE target cost.

As the commenters note, a recent study by NREL, Conoco Phillips, and Iowa State has posited that, using technology currently available today, and based on public data, the cost of producing cellulosic ethanol from corn stover is estimated at \$5.14 per gge. This estimate is inconsistent with recent NREL estimates and assumes no additional improvements in technology and efficiency. NREL, DOE, U.S. EPA, and ARB are depending on the maturation of the current technology to reduce the production costs to make biofuels cost competitive with gasoline.

ARB recognizes that there is uncertainty in staff's and other organizations' estimated production costs. We understand that the economic analysis of the LCFS is greatly affected by future oil prices and the actual production costs and timing of lower-carbon-intensity alternative fuels. Economic factors, such as tight supplies of lower-

carbon intensity fuels or a lengthy economic downturn keeping crude demand and hence prices down, could result in overall net costs, not savings, for the LCFS. We performed a sensitivity analysis using varying crude prices, feedstock prices, and interest rates and included the results in Chapter VIII of the ISOR.

I-3. Comment: The ISOR lists the feedstock cost at \$29 per dry ton based on a 2008 NREL study. However, a recent study by Sandia/GM identified biomass feedstock cost at \$40 per ton on the farm. The estimated delivered cost of feedstock to the plant is \$49 per ton. This estimate was made by adjusting the feedstock cost from another NREL study cited in the ISOR. (WSPA1)

Response: According to the UC Davis report for the Western Governors Association (WGA) entitled “Spatial Analysis and Supply Curve Development,” there should be sufficient biomass at \$20 per ton roadside to produce 900 million gallons of cellulosic ethanol. We estimated that a delivery price would be an additional \$10 per ton, which is consistent with UC Davis at a radial distance of 50 miles from a biorefinery. We assume that the biorefineries would be located in close proximity to available feedstocks, in this case wood chips. However, outside of the 50-mile radial zone, available biomass will be more expensive to collect and transport, making the feedstock more expensive for the biorefineries.

We conducted a sensitivity analysis for cellulosic ethanol from wood chips; the breakeven price was \$12 per ton without incentives. At this price, there would be insufficient biomass to supply the State’s biorefineries with feedstock. With incentives, the calculated breakeven point was calculated to be \$103 per ton, although this hypothetical figure indicates that sufficient biomass would be available to produce cellulosic ethanol at the State’s cellulosic ethanol plants.

I-4. Comment: Recent studies indicate the federal program capital cost is potentially \$11 trillion, so we question the very low estimates provided by ARB. We note that ARB’s outline doesn’t include new alternative fuel infrastructure expenses or the cost of alternative fuel plants. (WSPA1)

Response: Staff discussed the outline of our economic analysis at public workshops in December 2008 and January 2009. The outline may not have identified all infrastructure costs. In the complete economic analysis, we did include new alternative fuel infrastructure expenses and the cost of alternative fuel plants. We estimated that the total cost of the LCFS program would be the cost of the construction and operation of the biofuel refineries, the capital cost of the additional storage capacity of the biofuels, and the cost of the infrastructure necessary to dispense the lower-CI fuels (E-85, CNG, hydrogen, and electricity).

Up to eighteen cellulosic ethanol and six corn ethanol plants could be built by 2020 with a total annual capacity of 1.2 billion gallons, and five Fischer-Tropsch (FT) diesel and one Fatty Acid to Hydrocarbon (FAHC) diesel plant built by 2020 with a total capacity of

300 million gallons. The estimated capital investment for these new businesses is approximately \$8.5 billion (five corn ethanol plants are already built).

We estimate that 35 new ethanol storage tanks with a capacity of one million gallons per tank would have to be built to handle the required volumes of ethanol. The capital investment for installing these new tanks is approximately \$1.4 million dollars per storage tank or \$50 million total.

For E-85 dispensing infrastructure, assuming \$172,000 per installation, the total cost would be \$860 million for 5,000 stations. For hydrogen fueling stations, we estimate that 200 fueling stations would need to be built. At \$2.7 million per station, the total cost would be \$540 million. For CNG dispensers, we assumed 330 existing CNG stations would be upgraded and 70 new CNG stations would be added to existing truck stops. Assuming \$373,000 for upgrading an existing CNG station and \$1 million for a new CNG station at an existing truck stop, the total cost would be nearly \$200 million.

We estimated the total cost for these new/upgraded alternative fuel infrastructures and the cost of alternative fuel plants to be approximately \$10 billion over the next decade.

I-5. Comment: Based on an eight percent real discount rate per year with a capital recovery of ten years, we used a capital recovery factor of 14.90 percent, which we believe is extremely optimistic given that the technology has not been demonstrated in commercial scale. An average venture capital return rate exceeds 20 percent. (WSPA1)

Response: Because of the increased risks of investing in biorefineries, especially cellulosic ethanol plants that have only been built on a pilot-plant scale, we used a real interest rate of eight percent for a 10-year project life. A mature chemical industry might attract capital at a real interest rate of five percent over a 20-year period.

I-6. Comment: Regulatory uncertainty will worsen the potential supply problem. Therefore, it is essential that the LCFS regulations assure capital recovery for projects that are compliant when conceived. Fifteen years from project conception or ten years from conversion plant startup are reasonable. (A2O4NESTE2)

Response: We believe that the regulation is clear enough to attract investment capital to build the necessary biorefineries and other infrastructure.

I-7. Comment: The ISOR estimates a capital investment for ethanol produced from ligno-cellulose at \$309.7 million for a 50 MGY facility based on an earlier NREL study. A more recent NREL study estimates the capital cost for a similarly sized facility at \$376 million. (WSPA1)

Response: Our estimates were based on published studies by NREL and others that were available at the time the analysis was conducted. Our estimated capital costs are consistent with currently proposed commercial-scale cellulosic ethanol plants.

I-8. Comment: The economic assumptions regarding construction of new biorefineries and related infrastructure appear to be too optimistic, especially in light of the overall economic situation and current ethanol industry challenges. The report assumes the capital cost for a corn-to-ethanol plant at \$1.42/gallon – a more realistic assumption would include capital cost and owner cost (local owner cost for other buildings, offices, rail, etc.) of approximately \$1.90/gallon. (DUPONT1)

Response: Our capital cost estimates are based on surveys of existing corn to ethanol plants which were reported to United States Department of Agriculture (USDA) and Kansas State University. According to the USDA, “the average capital cost of building new ethanol plants is lower than in the past, possibly due to larger plant design that more fully exploit economies of scale.” The economy of scale asserts that an increase in production capacity can be achieved with a smaller increase in capital cost.

I-9. Comment: At the current offset costs (which are expected to increase over time), \$18.4 million would be required to purchase offsets for facilities located in the Central Valley. (In the South Coast Air Basin, the offset costs would be more than twice this amount, assuming the rules were changed to give biorefineries access to the “priority reserve” of NOx offsets.) Based on our independent analysis, an additional \$4.3 million is required to cover the cost of the SCR system. Ignoring permit fees, the air pollution control requirements increase NREL’s most recent capital cost estimate for a 50 million gallon per year facility to \$399 million. Assuming a very conservative 10 percent discount rate to recover the capital investment over the same 10-year period assumed in the ISOR, the amortization costs translates to \$1.30 per gallon of ethanol, which is \$1.94 per gge. (WSPA1)

Response: We did not account for the cost of offset credits that would be required to build these biorefineries. Adding the offset credit cost of \$18.4 million with the estimated cost for a Selective Catalytic Reduction (SCR) system, which we estimated at \$2 million, the estimated capital cost would be \$330 million (based on the NREL estimate of \$310 million). Using an eight percent discount rate over a 10-year period, this would yield an annual cost recovery of \$0.98 per gallon of ethanol, or \$1.45 per gge. In our economic analysis, we estimated the capital cost at \$1.37 per gge. This is an increase of \$0.08 per gge, or \$0.05 per gallon—still well within a cost-effective range.

I-10. Comment: The ISOR estimates that the cost of shipping ethanol from Northern California to Southern California at \$0.20 to \$0.30 per gallon. This seems to contradict the assumption that all ethanol production facilities will be located close to the point of end use. (WSPA1)

Response: We assume that the biorefineries will be built in close proximity to the available feedstocks, not necessarily close to point of end use. The final product will be shipped by truck and delivered to the blenders at a cost of \$0.20 to \$0.30 per gallon, based on data from existing ethanol plants.

I-11. Comment: The \$0.34 per gge cost estimates for STD (storage, transport, and distribution) does not appear unreasonable, considering the distance (from the Midwest to California). However, an additional \$0.10 per gge must be added to account for profit at the retail level, which was ignored by the ISOR. (WSPA1)

Response: Our analysis is based on production costs, not prices, which contain profit margins.

I-12. Comment: Our estimate for the net cost, excluding taxes, of cellulosic ethanol is \$3.98 per gge, which exceeds the estimated baseline fuel cost by 64 percent. With approximately 3 billion gallons of ethanol required in fuel for gasoline vehicles, the annual cost increase to California motorists is approximately \$3.1 billion. This is the cost only for the gasoline portion of the regulation. (This reflects the cost of all required ethanol, some of which would be required under the federal RFS.) (WSPA1)

Response: According to Sierra Research, the cost to produce cellulosic ethanol is approximately \$3.98 per gge. This cost estimate is based on a capital cost of \$1.94 per gge (which includes offset credits and installation of an SCR system, as mentioned above), a feedstock cost of \$1.08 per gge, a production cost of \$0.66 per gge, a co-product credit of \$0.14 per gge, and distribution and marketing costs of \$0.44 per gge.

Capital Cost: We estimated the capital cost of a cellulosic ethanol plant at approximately \$1.37 per gge; this translates to a \$310 million plant. Our estimates are based on published studies by NREL and others. Our estimated capital cost is consistent with currently proposed commercial-scale cellulosic ethanol plants.

Feedstock Cost: We estimated the feedstock cost at \$0.47 per gge; this translates to \$30 per ton biomass. According to the UC Davis Report for the WGA entitled "Spatial Analysis and Supply Curve Development," there should be sufficient biomass at \$20 per ton roadside to produce 900 million gallons of cellulosic ethanol. We estimated that a delivery price would be an additional \$10 per ton, which is consistent with UC Davis at a radial distance of 50 miles. We assume that the biorefineries would be located in close proximity to available feedstocks.

Production Cost: Sierra Research concurs with ARB staff on production cost.

Co-product Credit: Sierra Research concurs with ARB staff on co-product credit cost.

Distribution Cost: We estimated the cost of storage, transportation, and distribution (STD) from the federal Renewable Fuel Standard (RFS1). The estimated STD cost of ethanol from the Midwest is approximately \$0.34 per gge. Our analysis is based on production cost and not on profit gains by the retailers.

I-13. Comment: The costs of procuring feedstock for California facilities are also underestimated (distance, mode of transport, etc.) and, as the authors rightly note, greatly impacted by multiple other factors including oil and agricultural commodity prices. (DUPONT1)

Response: As noted above, we based our wood biomass costs on a report by UC Davis for the Western Governors Association. We based our corn stover costs on market value at the time the ISOR was published. Whereas some reports that we reviewed asserted a negative cost for municipal solid waste (MSW) because of avoided tipping fees at the landfills (i.e., the biorefineries charged a lesser tipping fee), we used a more conservative cost-neutral estimate of \$0/ton with no co-product credit. Since these materials are already delivered to landfills, we assumed that the vegetative portion of MSW can be delivered to biorefineries instead, hence the cost-neutral feedstock price.

We conducted a sensitivity analysis for cellulosic ethanol from wood chips; the breakeven price was \$12 per ton without incentives. At this price, there would be insufficient biomass to supply the State's biorefineries with feedstock. With incentives, the calculated breakeven point is calculated to be \$103 per ton, although this hypothetical figure essentially indicates that sufficient biomass would be available to produce cellulosic ethanol.

I-14. Comment: Ethanol makes sense when it is made from wastes which will make the equivalent amount of carbon dioxide if not turned into fuel. The well (raw materials) to wheels analysis should make any alternative at least as good as the electric vehicle or "natural gas" vehicle based on anaerobic digestion or non-air blown gasification of wastes. Let us not make the mistake of the 1980s wherein uneconomical and energy deficient processes were commercialized and failed by the scores with wind energy being the only real survivor here in CA. CARB can lead the way by implementing strict energy and emissions criteria that will prove benefits and not just create "ventures" that will fail in keeping the air clean as well as economically. We need to stop composting and turn that material into fuels. (APCINC)

Response: The adoption of an LCFS will expedite and reward the commercialization of lower-CI fuels (including waste-derived ethanol), making them competitive more quickly than if no regulation were in place. In addition to the LCFS program, the RFS2 will also depend on cellulosic ethanol. To promote the commercialization of the biofuel industry, DOE is funding research and development projects for cellulosic ethanol.

I-15. Comment: Staff includes a positive value of co-products of alternative fuels in their economic analysis. This appears to overstate their benefits and reduce costs, creating the perception of value greater than what may be real. (CSBR3)

Response: The benefits of the co-products are real. Dried distiller's grains (DDGS) from the corn-to-ethanol production are sold to dairy farmers as animal feed; excess electricity produced from cellulosic ethanol production and Fischer-Tropsch diesel process may be sold to the grid; and crude glycerin from the FAME biodiesel process can be sold to a chemical manufacturer. We based the value of these co-benefit products on current market values.

I-16. Comment: It also does not appear anywhere in their economic analysis that staff has factored in research and development costs for lower carbon intensity alternative transportation fuels. (CSBR2, CSBR3)

Response: We did not attribute research and development costs to the LCFS program. There is already considerable research being conducted for the federal RFS2 and other programs, most of which is funded by the federal government, especially the Department of Energy (DOE).

I-17. Comment: The clear problem and most significant issue facing CARB and the State is that there are not adequate amounts of commercially available "low carbon" alternatives to meet the goals of LCFS in the short term. There is also no certainty of their availability in the longer term. The technology for producing ethanol from cellulosic feedstock has not been proven on a commercial scale and no commercial plants have been built. There is no sound basis for the eventual cost for such a facility or its yield. There are estimates for these costs and yields but until a plant is built and operating, these numbers are speculative. (TESORO1)

Response: We concur that cellulosic ethanol technology is in its infancy. We estimated the overall production cost for these biofuels from published studies by NREL and others, but recognize that there are uncertainties in our and other organizations' estimated production costs. The regulation will undergo periodic review in 2011 and 2014. The availability of lower-CI fuels and the economic impacts of implementing the LCFS will be part of these reviews.

I-18. Comment: Staff uses interest rates (discount factors) for their analysis that are not reflective of current markets risks, returns, and risk premiums. Staff admits that at higher market rates the estimated savings will disappear. Current market conditions and rates, if used by staff, would show major costs/losses (not savings), with no other changes to their methodology, due to the implementation of LCFS or any other portion of AB 32. (CSBR2, CSBR3)

Response: Because of the increased risks of investing in biorefineries, especially cellulosic ethanol plants that have only been built on a pilot-project scale, we used a

real interest rate of eight percent for a 10-year project life. A mature chemical industry might attract capital at a real interest rate of five percent over a 20-year period, which is typically what ARB staff uses for other regulations that require the construction of large capital assets.

We maintained the 10-year project life and looked at the sensitivity of adjusting the real interest rate downward to five percent and upward to 10 percent. For this sensitivity analysis, we chose Gasoline Scenario #2 and Diesel Scenario #1, the two scenarios that require more liquid biofuels than the other gasoline and diesel scenarios, respectively. The breakeven interest rate for diesel is about 13 percent. The Fischer-Tropsch diesel process is capital-intensive; therefore, it would be more affected by interest rates than other processes. Conversely, cellulosic ethanol—with a tax credit of \$1.01/gal (\$1.50/gge)—can endure a much higher interest rate before the cumulative savings from 2010-2020 is driven to zero. Nevertheless, under such a scenario, the LCFS would result in overall costs from 2010-2016 of \$1.3 billion and overall savings from 2017-2020 of \$1.3 billion.

I-19. Comment: Staff does not elaborate on how the financing of the new production facilities, or of the required investments for both production and distribution will occur. In the current environment where credit markets still appear frozen where will the capital come from? (CSBR2, CSBR3)

Response: The costs associated with the expected biorefineries in the State will be borne by the investors of those facilities. These investors will risk capital with the expectation of being rewarded with profits commensurate with the risk. The carbon-intensity (CI) standards in the LCFS are back-loaded, meaning more GHG emissions reductions and corresponding compliance costs will occur in the later years of compliance when lower-CI fuel technology has matured and been commercialized. The LCFS compliance schedule allows time for future investments to be made in California-based biofuel technologies when the economy has had a chance to improve.

I-20. Comment: While the Staff Report claims that the costs of the rulemaking will be passed on to the consumer, it arbitrarily ignores the different situation Paramount is in as a result of its configuration, size and access to capital and infrastructure.

Because of economies of scale, even if Paramount had exactly the same variable costs associated with LCFS compliance as the major oil companies, any additional fixed costs to plan, monitor, operate and administer the program will cost Paramount fifteen times more per gallon of product than the average major oil companies and approximately ten times the cost per gallon of the next larger California refiner, ExxonMobil. (PP1)

Comment: The seven major oil companies in CA will dominate the markets for both low carbon blendstocks and LCFS credits, since they will be the buyers of over 98 percent of the blendstocks and credits. Paramount won't have the same

access or power in these markets as the next largest California refiner, ExxonMobil. (PP1)

Comment: The seven major oil companies (and particularly the five integrated companies) have significantly more access to capital to invest in alternative fuel manufacturing facilities that will provide them with assured dedicated low carbon blendstock supplies. In addition, they have the resources to hire additional staff to administer the LCFS program, and also have staff to research, plan, design, build and operate new blendstock producing facilities. (PP1)

Comment: Paramount is not physically located near the coast and does not have dock and tank facilities to obtain blendstocks by the cheapest transportation mode. The major refineries have this capability. Paramount will likely purchase blendstocks from a major oil company that owns or controls these facilities and thus Paramount will be at the mercy of competitors for its very survival. Any seller that will be willing to provide this service or access to a competitor will most probably do it at a substantial mark up. Additionally, the smaller volume requirements of blendstocks needed by Paramount would require inefficient delivery employing the use of smaller, less available vessels that are controlled by the sellers, or Paramount will have to share loads with the major oil companies. Paramount is also constrained by space for blendstock storage. The existing footprint of Paramount's facilities can't be extended to provide additional tank storage and existing tanks are heavily utilized. Thus additional storage, if available must also be made available by its competitors. (PP1)

Response: Current gasoline blends contain about 10 percent ethanol (E10). The LCFS will not change this blend. The source of the ethanol will change, however, to those suppliers who can produce it with lower carbon intensities. As a commodity, ethanol will continue to be purchased on the market, and staff does not believe that any particular fuel producer will have a significant competitive advantage when purchasing that commodity.

Staff has estimated that each regulated party will require one staff person—at \$170,000 salary, benefits, and overhead—to administer the LCFS program. Smaller regulated parties, such as small refiners, will absorb this cost in fewer gallons of fuel, but considering the millions of gallons of fuel sold annually by small refiners, this amount is insignificant.

Finally, the LCFS will not require modifications to the refining process. Staff assumes that the current ethanol infrastructure necessary to produce E10 will be sufficient to continue producing E10. E85, which is 85 percent ethanol, is available today for flexible-fueled vehicles. The volume of this fuel will increase throughout the next decade as more ethanol is introduced into the market; however, no specific fuel provider will have to participate in that market.

I-21. Comment: The costs of storage, transportation, and distribution are not static. The demand and supply cycles associated with them and the resulting prices can experience changes, disruptions, and additional costs that staff has not factored in. (CSBR2, CSBR3)

Response: We estimated the cost of storage, transportation, and distribution of ethanol biofuels from out-of-state by rail at \$0.23 per gallon. According to a California biorefinery, the cost to transport ethanol within the State by truck is estimated to be \$0.20 to \$0.30 per gallon. Although we recognize that unforeseen disruptions can affect the cost of transporting fuels, we believe that the fuel suppliers will build the necessary infrastructure (e.g., storage tanks) to account for short-term disruptions.

I-22. Comment: ISOR estimates for cellulosic ethanol range from \$2.31 to \$3.74 per gasoline gallon equivalent (gge), excluding taxes. The low end of this range is below our estimate of the baseline gasoline price; however, the \$2.31 per gge estimate assumes the feedstock is municipal waste with a feedstock cost of \$0.00. (WSPA1)

Comment: Also, the additional processing required for using “free” MSW adds uncertainty to the total system cost. (WSPA1)

Response: We estimated the cost of municipal solid waste (MSW) as feedstock at zero. (MSW refers here to grass, wood, and the paper portion of municipal waste.) Whereas some reports that we reviewed asserted a negative cost for municipal solid waste (MSW) because of avoided tipping fees at the landfills (i.e., the biorefineries charged a lesser tipping fee), we used a more conservative cost-neutral estimate of \$0/ton with no co-product credit. Since these materials are already delivered to landfills, we assumed that the vegetative portion of MSW can be delivered to biorefineries instead, hence the cost-neutral feedstock price.

I-23. Comment: Information regarding the timing of capital investments and annual expenditures to repay those investments was not provided. (CSBR1)

Response: Estimating the timing of capital investments for the LCFS is challenging because biorefineries are currently being built to satisfy the federal RFS2 requirements; some of the ethanol produced from these plants may be shipped to California. Nevertheless, we estimate that the potential 25 biorefineries that may be built in the State would have to be built within the 2013 - 2017 timeframe, most likely in 2016 - 2017.

Other Biofuel Costs

I-24. Comment: Biodiesel derived from soy oil is significantly more expensive than petroleum derived fuel. We estimated the wholesale price of biodiesel at \$2.15 - \$2.43 per gallon, which includes the \$1.00 per gallon tax credit and the exclusion of transportation cost. On April 22, 2009, the wholesale price of ULSD

was \$1.41 per gallon. Even with the \$1.00 per gallon federal blending credit applicable to biodiesel, the renewable fuel was still significantly more expensive than the average price of ULSD.

The price comparison of biodiesel to ULSD shown above is not an anomaly as the price of soybean oil has varied directly with the price of crude oil. Even during the record high diesel prices during the summer of 2008, biodiesel remained more expensive than ULSD. (ATA)

Response: According to the Energy Information Administration (EIA), the average price of crude oil for the month of April 2009 was approximately \$48 per barrel. Our economic analysis is based on crude prices of \$66 to \$88 per barrel, which would result in diesel production costs of \$2.28 - \$2.99 per gallon. If crude oil prices drop again to levels well below our assumed values, we concur that the alternative fuels will not be cost-competitive with petroleum based fuels.

To account for the impact of higher crude prices on the cost of producing biofuels, we adjusted both feedstock costs and production costs. (See Table VIII-9 in Volume I of the ISOR.) Based on information from “Ethanol Production Using Corn, Switchgrass, and Wood; Biodiesel Production Using Soybean and Sunflower,” 20 to 35 percent of the cost of growing corn or soybeans is related to fuel costs. These costs include diesel, gasoline, fertilizer, electricity, and transportation costs.

I-25. Comment: Biodiesel historically was more expensive than petroleum diesel. And this is because it was made primarily from soybean oil, which is a quite expensive raw material. California's biodiesel derived from waste cooking oil, which is also the trend nationally—about 50 percent of biodiesel now is made from waste—is actually able to be priced at or below the price of ultra-low sulfur diesel. And we're selling biodiesel today in Southern California for significantly less than the price of ultra-low sulfur diesel. So this is not a high cost solution. (TELLURIAN)

Response: Our economic analysis estimated waste-oil-derived alternative diesel fuels to be considerably less expensive to produce than soybean-based biodiesel. (See Table VIII-8 in the ISOR.) The commenter's current experience affirms those estimates. However, the amount of waste oil available to produce alternative diesel fuels is limited, and we believe that biomass-derived alternative diesel fuels—such as Fischer-Tropsch diesel from wood chips—will also have to be produced. These can be more expensive to produce than ultra-low sulfur diesel, so to be competitive, we estimate that crude prices must be at least \$80/bbl after 2015, and that the federal tax credit of \$1.00/gal must remain in place.

I-26. Comment: The LCFS assumes that biodiesel has the same energy content as conventional diesel. Actually, biodiesel has about a 10 percent lower energy content compared to ULSD. This lower energy content translates to lower fuel economy. The 838 million gallons of biodiesel anticipated to be used under the

LCFS in 2020 would have the same energy content as 755 million gallons of ULSD. The need to use an extra 84 million gallons of biodiesel is a significant cost that should not be ignored. (ATA)

Response: According to published data, B100 has an 8.65 percent fuel penalty, B20 has a 1.73 percent fuel penalty, and B5 has a 0.17 percent fuel penalty. We estimated the maximum biodiesel blend at 15.4 percent (Diesel Scenario #1), which has an estimated one percent fuel penalty, not a 10 percent fuel penalty. Staff considers this insignificant.

I-27. Comment: While CARB's staff currently expects the cost of low-carbon fuels to be effectively comparable to that of conventional fuels, there is a substantial probability that this will not be the case. Changes in the cost of conventional fuels or in the cost of low-carbon fuels could easily alter the annual cost of meeting the LCFS target by billions of dollars. (WSPA1)

Comment: Cost estimates for alternative fuels are unrealistically low due in part to unrealistic estimates for feedstock cost, unrealistic estimates of the cost of emissions control requirements on biomass refineries, and unrealistic assumptions regarding the cost of capital—the combination of these factors leads CARB staff to underestimate the cost of the LCFS by over two billion dollars per year. (WSPA1)

Response: Our economic analysis is based on several assumptions:

- a. Crude prices will be \$66 - \$88/bbl during this time period (based on the California Energy Commission's [CEC] 2007 Integrated Energy Policy Report);
- b. The cost of producing cellulosic ethanol will decline as technology improves and the industry matures (based on National Renewable Energy Laboratory [NREL] estimates);
- c. Feedstock costs were based on currently available information; and
- d. Current tax incentives for biofuel production will be renewed throughout this timeframe.

We have stated that, if these assumptions ultimately prove to be incorrect (i.e., there are actually lower crude prices and higher biofuel production costs), the LCFS could have net costs, not net savings.

To account for uncertainty, we conducted sensitivity analyses for key parameters, including crude prices, feedstock costs, and real interest rates. (See VIII-34 – VIII-36 of the ISOR.) These analyses showed that the LCFS is cost-effective over a wide range of assumptions.

Regarding the cost of emissions control requirements on biomass refineries, please see the response to Comment I-9. Regarding the cost of capital, please see the response to Comment I-5.

The regulation requires ARB to conduct reviews of the LCFS in 2011 and 2014. These reviews will include assessing the cost and availability of alternative fuels. Should the LCFS be determined to be costly to California's economy due to unrealized assumptions or prevailing economic conditions, staff may return to the Board to revise the regulation.

I-28. Comment: As shown in Table VIII-8 of the ISOR, the feedstock cost for biodiesel alone is estimated to be \$2.62 per gallon of fuel produced, which already exceeds our \$2.48 per gallon baseline cost estimate. When other factors are accounted for, the ISOR estimates the total price for biodiesel at \$3.15 per gallon. With another 3 percent added to account for profit at retail, the total cost, excluding taxes, is \$3.24 per gallon, 31 percent higher than the price of the baseline. Assuming 838 million gallons are required for compliance, the cost increase to motorists is \$637 million per year. (WSPA1)

Response: The commenter's analysis fails to consider the \$1.00 per gallon tax credit for alternative diesel fuels, which will result in a potential net savings that can either be taken as profit by the fuel manufacturers or passed on to consumers. Furthermore, profit margins are not considered in the cost-of-production analysis conducted by staff, but are included in a *price* analysis.

I-29. Comment: The LCFS should not place an emphasis on placing E85 filling stations throughout the State. This part of the LCFS is guiding investment into potentially wasteful activity. Please drop any reference to E85 infrastructure until there is a clear low carbon way to produce the fuel. Wait a few years to see exactly where the ethanol industry is headed. (AIR)

Comment: Valero believes that the economic analysis prepared by CARB is overly optimistic and the potential cost of LCFS program could be significantly higher (i.e., E85 infrastructure costs). We are not aware of a solution to the problem of getting third parties to make the infrastructure investment for E85, when the economics of doing so are unattractive. (VALERO)

Response: We based our estimate to install E85 infrastructure at existing fueling stations on actual costs provided by a contractor. There is no requirement in the LCFS for any specific fueling station to install E85 pumps and sell E85 (or biodiesel). The infrastructure costs will be borne by the investors of those facilities. Fueling station owners and operators would presumably invest in equipment that dispenses LCFS-compliant fuel with the expectation that the costs of such an investment would be recouped through sales of such fuels.

I-30. Comment: We are concerned about the feasibility of the LCFS. All of the potential compliance scenarios rely on advanced biofuels that are not commercially available, advanced vehicles, and significant transportation fuel

infrastructure investments above the truck rack, at the truck rack, and at the retail outlets. (VALERO)

Response: For illustrative purposes, we used eight potential compliance scenarios in the economic analysis. Although the five gasoline and three diesel illustrative compliance scenarios included varying numbers of specialized vehicles, that analysis was conducted on a “what if” basis (i.e., What if there were one million ZEVs, or two million ZEVs?) We illustrated possible low-carbon fuel scenarios wherein the fuel mix satisfied the vehicle assumptions. The vehicles were not mandated. In addition, the CI standards in the LCFS are back-loaded to give lower-CI fuel technology time to mature and to be commercialized. Finally, the regulation will undergo periodic review in 2011 and 2014. The status of the biofuel industry, including the availability of lower-CI fuels, will be included in those reviews, and changes to the regulation will be made, where deemed appropriate.

I-31. Comment: Staff attributes nearly all of the ethanol related infrastructure costs to RFS2 but only 30 percent of the benefits through lower emissions. This shows a tendency to overstate the benefits and understate the costs by staff. (CSBR3)

Response: In the economic analysis, we attributed all costs to the LCFS. We then noted that most of the ethanol-related infrastructure would probably be built anyway because of RFS2 requirements, although we did not adjust our calculations to reflect that reality. Regarding the benefits of the LCFS, the baseline case did not take into account RFS2, although Governor Schwarzenegger’s Executive Order S-01-07 establishes a 10 percent CI reduction target by 2020.

Non-Biofuel Costs

I-32. Comment: Natural gas engines operate differently than diesel engines and in-house mechanics will require approximately 60 hours of specialized training. Natural gas engines may require fuel injectors to be replaced more frequently than diesel engines. For spark-ignition natural gas engines, replacement of spark plugs, ignition modules and various sensors add additional maintenance costs. In-house maintenance facilities may require expensive upgrades to address potential methane exposure (i.e., electrical modifications, sensors, ventilation). (ATA)

Response: The LCFS regulation does not mandate natural gas engines. In two of the three diesel scenarios, we illustrated that CNG-fueled engines can be used to help comply with the diesel CI standards. We do not doubt that the maintenance of natural gas engines is different than diesel engines and requires special training.

I-33. Comment: Building an LNG refueling station capable of refueling one truck at a time costs over \$500,000. Refueling multiple trucks simultaneously is significantly more expensive. (ATA)

Response: We estimated that an existing CNG fueling station can be upgraded to accommodate two trucks simultaneously by installing additional infrastructure, including a compressor, for \$373,000. For a new CNG fueling facility, we estimated a cost of \$1 million. These figures are consistent with the commenter's estimate.

I-34. Comment: In the economic analysis, application of the EERs reduces the effective cost of electricity and hydrogen used as gasoline substitutes. As a result the cost assumed translate to \$1.00 and \$2.38 per gge, respectively, both of which are lower than the \$2.92 assumed for gasoline in 2020. The cost differential for electricity contributes significantly to the cost savings staff claims for the LCFS, especially for those scenarios where high volumes of plug-in hybrid vehicles and battery electric vehicles are assumed. (WSPA1)

Response: Although plug-in hybrid vehicles and battery-electric vehicles are economical because of the high efficiency of their electric motors, their deployment in the illustrative compliance scenarios did not significantly skew the cost-effectiveness of the scenarios. For example, Gasoline Scenario #4 had nearly 1.8 million electric vehicles on the road by 2020—by far the most of any of the other scenarios—yet the overall cost effectiveness of that scenario was second to Scenario #1, which had 560,000 ZEVs. Furthermore, we estimated that the total amount of electricity that these electric vehicles in Scenario #4 would use in 2020 would be 4.6 million megawatt-hours, which represents one percent of the total energy required for the vehicle fleet that year.

I-35. Comment: Electric, hydrogen and compressed natural gas may be used to meet the requirements of LCFS but their expected time to market is much longer than grain and cellulosic ethanol, and will require significant investment in new infrastructure (with related costs and full impacts yet to be determined). (DUPONT1)

Response: We included the infrastructure costs of non-liquid alternative fuels in our economic analysis. Although the LCFS does not mandate these alternative fuels, we believe that they will be deployed to help comply with the LCFS. The market will determine both the timing and penetration of these alternatives.

I-36. Comment: Use of lower EERs like those that are effectively imposed by the Pavley regulations would increase the estimated cost of the LCFS regulation in the gasoline substitution scenarios and decrease the estimated reductions in greenhouse gases emissions. (WSPA1)

Response: The GHG emissions reductions achieved by the LCFS did not include the GHG reductions attributable to the Pavley regulation. In this manner, we avoided double-counting emission reductions. Furthermore, since the LCFS does not mandate the use of ZEVs, the costs of the advanced-technology vehicles are not included in the LCFS economic analysis. Those costs are borne by the Pavley regulation and other regulations that mandate ZEV deployment.

I-37. Comment: The conversion to natural gas is prohibitively expensive; 1) natural gas engines are more expensive than diesel engines, 2) natural gas has lower energy content than diesel fuel, 3) fuel tanks weigh more which in turn reduces the truck's fuel efficiency. (ATA)

Comment: Building out a natural gas refueling infrastructure along key freight corridors will take time and may result in a monopoly pricing situation, as there is unlikely to be significant pricing competition among fuel vendors due to the high barriers of entry. A competitive fuel model would require the presence of multiple entities selling LNG in the same geographic area. (ATA)

Response: The regulation does not mandate CNG- or LNG-fueled vehicles, or the infrastructure necessary to accommodate them. The market will determine the extent to which these vehicles are deployed to meet the requirements of the LCFS.

Vehicle Cost/ Availability

I-38. Comment: The economic analysis fails to consider increased vehicle costs for plug-in hybrids, electric and hydrogen cars. (AB32IMPG1)

Comment: The ISOR economic analysis ignores the incremental costs associated with specialized vehicles when calculating the net cost of the LCFS. These are real costs that would be borne by some entity, most likely California consumers, and that would have an impact on California's economy. Depending on the compliance scenario, these incremental costs range from \$14 to \$47 billion over the period 2010 to 2020, as compared to the staff's claimed \$11 billion cost savings for the LCFS. (WSPA1)

Comment: Staff assumes that there will be no costs associated with technology advancements needed to make the vehicles commercially affordable and reasonably priced. Staff also does not account for the possibility that consumers will have to pay substantially higher prices as they already do for those more fuel efficient and advanced technology vehicles and the associated economic costs and impacts. (CSBR2, CSBR3, CSBR4)

Comment: What will the vehicles cost? (LBA1, LBA2)

Response: We do not believe that the cost of specialized vehicles should be included in the economic analysis for the LCFS because the LCFS does not mandate deployment of these vehicles. Although the five gasoline and three diesel illustrative compliance scenarios included varying numbers of specialized vehicles, that analysis was conducted on a "what if" basis (i.e., What if there were one million ZEVs, or two million ZEVs?) We illustrated possible low-carbon fuel scenarios where the fuel mix satisfied the vehicle assumptions. The vehicles were not mandated.

Additional zero emission vehicles (e.g., battery electric vehicles, plug-in hybrids, fuel cell vehicles) may occur through additional mandates by the Board or consumer preferences. If California mandates the development of additional ZEVs, the costs and economic impacts of those vehicles should be borne by the ZEV program, not the LCFS.

The federal RFS2 will bring more than three billion gallons of ethanol to California, with or without the LCFS. This volume will determine the need for E85 and the number of FFVs in the State. Since the LCFS requires no greater total volume of ethanol than RFS2, we believe the marginal cost of FFVs should not be attributed to the LCFS.

I-39. Comment: Staff assumes that there will be adequate availability of vehicles utilizing alternative fuels. (CSBR2, CSBR3, CSBR4)

Response: The availability of vehicles utilizing alternative fuels will depend on future mandates and consumer preference. If the Board adopts future mandates for specialized cars, more of these cars will be on the road between 2011 and 2020 (the LCFS compliance period). In addition, if these cars can operate on alternative fuels that eventually become cheaper than traditional fuels, consumer demand for them will most likely increase above mandated levels. For illustrative purposes, we used eight potential compliance scenarios in the economic analysis. We assumed a specific number of alternative-fueled vehicles per year in each scenario, which may or may not actually occur.

I-40. Comment: The nation is now in the midst of an economic recession that is likely to severely reduce the number of new vehicles purchased over the next five years. Any plan to achieve carbon reduction from transportation fuels based on new electric, hybrid, plug-in hybrid, or increased efficiency conventional vehicles will not be supported by the economic conditions, absent major government subvention. Consequently, the state is likely to see the average age of automobiles on the road increase from seven to 12 or more years as people postpone new car purchases because they can't get credit or simply don't have the money. This will result in a reduction in or stagnation of increased fuel efficiency gains due to new vehicles put in service. (KEMPF)

Response: We recognize that the current economic conditions may result in consumers owning their cars longer than in the past. The federal government, in response to this situation, created the "Cash for Clunkers" program, which was successful at placing more fuel-efficient cars on the roads. The federal government may pass similar programs in the future, if warranted. Future car buyers will have to consider the operating cost of specialized vehicles. As alternative fuels become more competitive with traditional fuels in future years, specialized cars will become cheaper to operate, and consumer demand for the vehicles should increase.

I-41. Comment: Another issue is CARB's assessment of the benefits of the federal Renewable Fuels Standard (RFS2). In the ISOR, CARB staff acknowledges that

even in the absence of the LCFS, the RFS2 would yield about one-third of the total GHG reductions. What CARB staff fails to acknowledge is that all of these benefits will likely result from the use of renewable fuels in existing vehicles, rather than specialized vehicles, in which case the only costs that are material in the economic analysis are the costs associated with fuel production and distribution. CARB staff also fails to acknowledge that in order to achieve a significant fraction of the rest of the reductions claimed for the LCFS, it has had to assume that there would be large volumes of expensive specialized vehicles and a proper accounting would show that the incremental cost-effectiveness of the LCFS relative to the RFS2 is poor. (WSPA1)

Response: We do not agree that all of the volume of renewable fuels required in the RFS2 will be used with existing vehicles. Assuming the State receives its historical 11 percent proportional share of national gasoline volume, RFS2 will bring more than three billion gallons of ethanol to California, the same volume needed for the LCFS. More E85 and FFVs would be needed in the State to accommodate the federally-mandated volumes of ethanol.

We estimate that, despite achieving additional GHG emission reductions, the LCFS will not result in incremental cost or savings relative to the RFS2, primarily due to the fact that the vast majority of the infrastructure costs related to importing, storing, distributing, and dispensing ethanol in California will occur under RFS2, independent of California's adoption of the LCFS.

Tax Credits

I-42. Comment: Staff assumes that the current \$1.01 per gallon tax subsidy for cellulosic ethanol will be extended indefinitely. (WEITZMAN1, WEITZMAN2, WSPA1)

Comment: Staff assumes that the federal \$1.00 per gallon tax credit for biodiesel will be extended indefinitely. (WSPA1, ATA)

Comment: If Congress does not act to extend this tax credit, then the cost of biodiesel could be almost double the cost of ULSD. Even a low percentage blend, such as B5, could cost consumers an extra 10 cents per gallon. (ATA)

Comment: The subsidies assumed to continue beyond current expiration dates are not treated as costs. If they were, the net cost of the LCFS would be positive, not zero or negative as claimed by CARB staff. (WSPA1)

Comment: It appears that the cost of production of alternative fuels is artificially lowered due to the associated tax incentives offered for their use. In economic terms, these incentives represent a cost borne by tax payers since they are revenue not collected by the state since such incentives are not available for all fuels. In this sense the users of alternative fuels are essentially being subsidized

by those who are not using these fuels. This not only distorts the true costs of alternative fuels but also renders the comparisons to traditional fuels unfair. (CSBR2, CSBR3, CSBR4)

Response: We believe that it is appropriate to include tax credits in the economic analysis, as this analysis was done on a cost-of-compliance basis, which is an analysis that is consistent with other ARB regulations. Congress has chosen to create tax credits for alternative fuels in order to promote their commercialization and make them more competitive with traditional transportation fuels. We believe it is appropriate to assume these credits will be extended beyond current expiration dates because this has historically been the case and the cost-competitiveness goal for biofuels has not yet been achieved.

I-43. Comment: Staff has indicated that the LCFS will result in lost revenue to Government. Staff should provide cost estimates of these revenue losses during the periodic program reviews. (CONOCO)

Response: We applied the alternative-fuel tax incentives to the cost-effectiveness analysis and analyzed the fiscal impact those incentives would have on government revenue. The LCFS program will be reviewed in 2011 and 2014. The economic impacts of implementing the LCFS (including revenue impacts from tax credits) will be part of these reviews.

I-44. Comment: Almost all of the ethanol used in California comes from the Midwest corn that leads to limited or no carbon benefits from ethanol use. CARB could immediately improve the carbon benefits of LCFS implementation if corn based ethanol were replaced with sugarcane ethanol. This could be accomplished by having CARB write a letter to the US EPA seeking a waiver from having Brazilian ethanol pay the 54 cent import duty on ethanol landed in California as a means to achieve carbon reductions from the use of ethanol in the State of California. If this led to substitution of corn based ethanol with Brazilian sugarcane ethanol the lifecycle carbon reductions would result in a 4.5 percent improvement in carbon emissions from fuel and could be accomplished in the near term. This could be justified given that EPA has ruled that carbon is a hazardous emission and should be regulated. (CO2STR)

Comment: When it comes to biofuels we believe that the production of ethanol in Brazil should not be unduly hindered by these current trade policies. We believe sugarcane ethanol is a lower carbon biofuel available in volume for compliance in the early years of the LCFS. We encourage California to acknowledge the opportunity that Brazilian sugarcane ethanol offers for LCFS compliance by advocating for the suspension of import tariffs. Such an acknowledgement would be a strong signal to policy makers in Washington that California is serious about achieving the GHG mitigation goals laid out in the LCFS and AB 32. (BP1)

Response: The carbon-intensity (CI) values established for sugarcane ethanol demonstrate that this biofuel can be an important component of the lower-CI fuel mix during the early years of the LCFS, which may encourage Congress to sunset the tariffs. Nevertheless, advanced biofuels—made from waste products that have little or no indirect land use effects—are the future for low-carbon transportation fuels. U.S. EPA staff is assessing this issue, and ARB staff will coordinate with them on these efforts.

LCFS Fees

I-45. Comment: There may be other hidden costs to the LCFS. On page ES 22 of the Staff Report, staff writes "Pursuant to H&S section 38597, staff is also considering inclusion of a schedule of fees, to be paid by the regulated parties, to fund the use of third party services." The economic analysis makes no mention of costs or fees that are under consideration that would have an economic impact on producers or consumers in California. (CSBR2, CSBR3)

Response: If ARB pursues an LCFS fee regulation, we will evaluate the economic impacts of the fees in a separate rulemaking process.

Recordkeeping/Enforcement Costs

I-46. Comment: Staff appears to underestimate the costs of reporting, monitoring, and enforcing compliance. Staff estimates that only \$4.6 million will be needed annually for record keeping and reporting, and only \$510,000 annually for enforcing the regulation. These estimates appear naive and grossly understated given our understanding of the bureaucratic processes and work load involved and the vast government machinery in California already at work. (CSBR2, CSBR3)

Response: The regulation requires affected parties to submit quarterly progress reports and annual account balance reports by specified dates. We estimated that it would take one person-year (PY) per regulated party to comply with the recordkeeping and reporting requirements. There are 15 refineries in California, four importers of CARBOB/diesel (in 2008), four in state ethanol producers, and four ethanol importers. Assuming \$170,000 per PY, annual reporting and recordkeeping costs would equal \$4.6 million for all affected industry.

We also estimated the resources needed to implement and enforce the regulation and to contact with third parties to certify particular aspects of regulated party's claimed fuel pathways. There will be no impact in FY 2009/2010. We estimate that three new positions will be needed for FY 2010/2011 and FY 2011/2012 – funded at \$170,000 per position per year, or \$510,000 annually.

Cost-Effectiveness

I-47. Comment: The Scoping Plan requires that AB 32 policies are cost-effective and deliver real global warming emission reductions while taking into account those policies' impacts on small business and low income families. The LCFS as proposed raises serious doubts about the cost-effectiveness of the program. Given the circumstances, perhaps resources should be focused on lower-cost, simpler strategies that will encourage energy efficiency and conservation without risking small businesses, jobs, and the economy. The Sacramento Hispanic Chamber of Commerce is asking you work with the public, Legislature and the Governor to develop more realistic priorities and cost effective policies. (SHCC1, SHCC2)

Comment: As a matter of fact, AB 32 requires that global warming policies be cost-effective and take into account economic impacts. There shouldn't have to be a choice between protecting the environment and protecting small businesses and the economy. There can and should be a reasonable balance between the two. A good start would be for you to postpone this rulemaking until all the legal requirements have been fulfilled and it can be demonstrated that it will be cost effective and environmentally relevant. (CBCOC1)

Comment: The adopting resolution for the Scoping Plan specifically called for a re-evaluation of cost-effectiveness and impacts to small business, to be delivered by December 31, 2009. However, this information should be completed and made available prior to designing regulations that will fundamentally alter California's economic and social landscape. (CHCOC1, CSBR1, CSBR2)

Comment: It seems you're making a lot of assumptions that are based on optimistic projections of folks who are in the business of making these fuels and vehicles or would like to and have a sincere desire to do something about global warming. This program needs more and deeper research. Please take the time necessary to come up with a cost effective and environmentally meaningful plan. (LBA1, LBA2)

Comment: We urge you to take the time to coordinate more closely with the federal government and other states to craft a standard that will be cost-effective and environmentally effective as well. (SDCHCC)

Comment: Before moving forward with the LCFS, the small business community would like to make sure that CARB fully evaluates the cost-effectiveness of the regulation. (CHCOC1)

Comment: Staff should consider and respond publicly to the ongoing peer review of CARB's LCFS economic analysis, and publicly identify how the LCFS economic analysis addresses the requirements of AB 32, California Health and Safety Code (HSC) section 43013, the Scoping Plan adoption resolution, and the

recommendations of the California Legislative Analyst and CARB's own peer reviewers in their assessment of the Scoping Plan economic analysis. (AB32IMPG1)

Response: We have met the requirements of AB 32 by relying upon the best available economic and scientific information and by assessing the existing and projected technological capabilities to reduce greenhouse gases. Staff believes we used reasonable assumptions and projections into the future to conduct the cost-effectiveness analysis. By approving the LCFS for adoption—and not postponing its consideration—the Board agreed with staff that the economic analysis, including the cost-effectiveness analysis, was complete and thorough. However, we understand that the economic analysis of the LCFS is greatly affected by future oil prices and the actual production costs and timing of lower-carbon-intensity alternative fuels. Economic factors, such as tight supplies of lower-carbon intensity fuels or a lengthy economic downturn keeping crude demand and hence prices down, could result in overall net costs, not savings, for the LCFS.

We assert that HSC 43103 does not apply to the LCFS regulation because the LCFS is not setting a fuel standard; however, the economic analysis nevertheless satisfies the requirements of 43013(f). Furthermore, the economic analysis satisfies the Scoping Plan resolution, which requires us to consider cost-effectiveness, the timing of capital investments, sensitivity of results to key input changes, and impacts on small businesses. Finally, the LCFS economic analysis is a separate analysis from the overall economic analysis of the Scoping Plan. The economic analysis of the Scoping Plan is being revisited as a separate staff activity. The LCFS economic analysis considers the compliance costs of meeting the proposed regulation, and has undergone independent peer reviews. Responses to all peer review comments on the LCFS are in Chapter B in this FSOR, including those pertaining to the economic analysis.

I-48. Comment: ARB staff's proposed methodology to update fuel pathway values at inconsistent times, potentially causing a sporadic reshuffling of the default value deck, will directly cause stranded investments that could be avoided. ARB should incorporate wasted investments in its evaluation of "cost-effectiveness." While ARB staff did evaluate cost-effectiveness by developing values for each compliance scenario modeled, their methodology ignores the substantial investments that will be wasted after it is eventually determined that a particular fuel type fails updated requirements, such as fuel specifications, sustainability criteria, etc. (CERA1, CERA2)

Response: The implementation of the LCFS will not result in wasted or stranded investments. The investments to construct the infrastructure for lower-CI fuels (e.g., biorefineries, ethanol storage tanks, fuel dispensing facilities) will be done with the expectation of being rewarded with profits commensurate with the risk. The regulation requires that modifications or additions to the fuel pathways and associated CI values be conducted in a public process, which will allow investors to make the most appropriate investment decisions. In addition, if ARB needs to establish fuel

specifications for lower-carbon intensity fuels developed later, those specifications will be developed in a public rulemaking process as well. Finally, the Board directed staff in Resolution 09-31 to work with stakeholders to present a workplan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation. The workplan will provide a framework for how sustainability provisions could be incorporated and enforced in the LCFS program, and a schedule for finalizing sustainability provisions by no later than December 2011, unless the Executive Officer determines that such actions are not feasible and not appropriate.

I-49. Comment: When performing the cost-effectiveness, ARB's current analysis of fiscal impacts seems to be focused on the out years of the program (i.e., towards 2020). Given this is the most speculative timeframe in terms of the nature and availability of the required technology it is relatively easy for staff to postulate on successful scenarios for complying with the LCFS. ARB should make different forecasts for the early years (nominally 2010-2015) than for the later years (nominally 2015-2020). The difference between the two would be the planned program reviews: in the early years (i.e., before the program reviews have an opportunity to have much of an impact) ARB needs to demonstrate that sufficient quantities of required low CI fuels using currently available technology will be available to meet the proposed goals. In the later years, the regulations need to reflect the greatest possible commitment (through the program reviews) to updating the feasibility analyses based on what actually transpires between now and then. (WSPA1)

Response: The LCFS standards are back-loaded in order to give time to commercialize the technologies needed to make lower-CI fuels. Consequently, the cellulosic ethanol volumes will be modest in the early years and most of the GHG reductions will occur in the later years of compliance. We conducted cost-effectiveness analyses for each year of compliance (2011-2020) using eight different compliance scenarios. These results are included in Appendix G of Volume II of the Staff Report. The regulation will undergo periodic review in 2011 and 2014. The status of the biofuel industry, including the availability of lower-CI fuels, will be included in those reviews and changes to the regulation will be made, where deemed appropriate.

I-50. Comment: We do know that there are lots of carbon intensity values for future fuel pathways that have not yet been determined. So we're unsure of the availability and cost effectiveness as we go forward meeting these by 2020. (WSPA1, WSPA3)

Response: Although not all fuel pathways have been determined, enough have been determined to allow compliance with LCFS. One of the purposes of the LCFS is to incentivize improvements to existing fuels and the development of new fuels. The LCFS through Methods 2A/2B allows staff and fuel producers a process to establish new pathway carbon intensity numbers. The regulation requires that all updated or new fuel pathways and associated CI values be developed in a public process and creates a mechanism for this process. It also requires an LCFS implementation review to be

completed by January 2012 and January 2015. The availability of fuels and the economic impacts (including the cost-effectiveness) of implementing the LCFS will be part of these reviews.

Fuel Reformulation Requirements (H&SC 43013)

I-51. Comment: Having followed the AB 32 process for some time now, I'm not convinced that your staff has completed the analysis required under the State's Health and Safety Code concerning costs, fuel supplies, performance, and environmental impacts. (CHCC1)

Comment: Without doing the economic, the environmental and the technical analyses, as required by law, CARB staff is asking you to believe that the goals of the LCFS can be achieved at minimal cost and that by commanding various fuel additives or new fuels to be introduced, that they'll actually be available, practical and affordable. (NFIB)

Comment: It seems that your staff has inadequately explored the availability of low-carbon fuels and the cost of such fuels to consumers or to small businesses, which I believe is required for a new fuel formulation. We feel you should take more time and do it the right way, especially since the United States and the world is watching what California does. (CBCOC3)

Comment: We are disappointed that, as was the case with the approval of the Scoping Plan last year, you are preparing to adopt a rule without conducting other environmental, performance and supply evaluations required by law. (CBCOC1, CBCOC2)

Comment: We would like to see the Board complete its work on the diesel portion of the regulation before adopting it, so that the performance, supply and price impacts can be realistically assessed. (WG)

Comment: Please do not require a low carbon diesel fuel standard before all the unintended consequences are examined and understood. CARB must be required to do the following before issuing an LCFS mandate:

- a. Establish what the fuel will cost.
- b. Establish if there will be ample supply.
- c. Establish how the increased cost associated with a new fuel will affect the California carrier fleet's ability to compete with carriers that do not use the same fuel.
- d. Conduct extensive testing to ensure that the new fuel will not damage engines and/or underground storage tanks and dispensing systems. (HTC)

Comment: In particular we're worried, since a lot of our businesses are heavy diesel fuel users engaged in agriculture and trucking, that the diesel component

of this rule will cause far more problems than it will solve. Our folks need to know:

- a. How much will the fuel cost?
- b. Will there be enough low carbon diesel available?
- c. Will the new diesel fuel cause performance problems or damage to existing diesel engines? (SJCHCC2)

Comment: We believe in order to get this right and to meet the LCFS goals, more analysis is needed. Specifically, we believe the following is needed to better understand the proposed rule: 1) Determine the critically important carbon intensities for biodiesel, renewable diesel, and advanced renewable diesel; 2) Complete the legally required multimedia analysis for biodiesel; and, finally, 3) Revise the economic analysis of the supply and price impacts of the diesel fuel carbon intensity specification reflecting the volume of products necessary for compliance. (CCOC)

Comment: Not only the Scoping Plan, but California's Health and Safety Code requires review of how new fuel standards will impact fuel supplies, fuel prices, fuel performance and the competitiveness of California's businesses. This analysis is critical in order to develop regulations that minimize impacts and protect small businesses. (CSBR1)

Comment: Testing and given the ability to test this new fuel formulation is quite important to us to see that it doesn't affect us in a negative way. We have thousands of people that we employ and want to keep employed. We don't want to jeopardize any of these jobs. How will these costs be distributed in real cash flow terms; out-of-pocket dollars that must be spent every day from the day of the program, not averaged over a period of many years. And then estimate energy cost savings that may or may not be realized much later. (WSGM)

Response: The proposed regulatory action does not establish any motor-vehicle fuel specifications because the LCFS contains no requirements that dictate the exact composition of compliant transportation fuels. California reformulated gasoline contains up to 10 percent ethanol, and the LCFS will not change that requirement. It will only make that ethanol have lower carbon intensity. Likewise, E85 (85 percent ethanol) is available today, but more volume of this fuel may be available in California in the future because of the LCFS and the federal RFS2. Because the proposal does not establish a motor-vehicle fuel specification, the multimedia evaluation, environmental evaluation, economic, and supply and performance requirements in Health and Safety Code (HSC) sections 43013 and 43830.8 do not apply. The LCFS economic analysis, nevertheless, satisfies the requirements of HSC section 43013(f).

If the Board amends specifications, such as the current E85 specifications, or adopts new specifications, such as those for biobutanol fuel, staff will conduct multimedia evaluations for the specific fuels and will satisfy requirements in HSC section 43013 and 43830.8. ARB has a multimedia evaluation already underway for the biodiesel and

renewable diesel fuel specification regulations, which staff expects to take to the Board for approval in 2010. Refer to responses in Chapter E (Legal Authority) for more discussion on the need for multimedia evaluations.

The carbon intensities of biodiesel and renewable diesel fuels are being developed. The basic numbers will be available as part of the rulemaking. The slow phase-in of the performance standards in the early years allows time for new fuel pathways to be established, and the LCFS regulation provides for establishing additional pathways as they are developed.

Biodiesel and renewable diesel fuels are already allowed in California's fuel mix and we do not expect engine performance issues to arise from the continued use of these fuels. Please refer to Chapter J (Compliance Scenarios/Technology Assessment) for more discussion.

I-52. Comment: The ARB needs to consider issues of state indemnification and liability if fuels under the LCFS damage private property or infrastructure, and the net fiscal impact this will cause amidst California's budget crisis. (CERA2)

Response: Consideration of state indemnification and liability of fuels were not included in the economic analysis because the LCFS program does not set fuel specifications. Refer to the responses in Chapter J (Compliance Scenarios/Technology Assessment) for more discussion on indemnification to address costs and other impacts due to possible engine performance issues.

Cost of Alternatives

I-53. Comment: Assessing the cost of the LCFS relative to the business-as-usual baseline should be a key element of CARB's analysis. However, CARB should also measure the cost of the LCFS relative to at least two alternative scenarios: a less stringent carbon-intensity requirement, and achieving comparable emission reductions through an economy-wide cap-and-trade system.

It is my understanding that the specific carbon intensity required under the LCFS was not selected based on the result of an economic analysis. Therefore, both CARB and Californians should be made aware of the incremental cost of meeting that particular carbon-intensity target, relative to the cost of meeting slightly less stringent carbon-intensity targets.

Similarly, even if the LCFS was not implemented, AB 32's 2020 emissions target would still be met as a result of the economy-wide cap-and-trade system that CARB is proposing to implement under the Scoping Plan. Therefore, CARB should evaluate the cost of implementing the LCFS relative to an alternative scenario in which LCFS is not implemented and the necessary emission reductions are achieved through the cap-and-trade program. While the LCFS clearly has policy objectives beyond just GHG reductions, given the ability to

achieve the GHG reductions through reliance on the cap-and trade system alone, CARB should understand the cost of achieving the LCFS's additional objectives. (WSPA1)

Response: We considered an economic assessment of two alternative approaches to the proposed regulation. Also, please refer to the response to Comment I-54 below for more discussion.

Chapter X of the Staff Report presented analysis of alternatives to the LCFS. Staff did not analyze a less-stringent-CI-requirement alternative because this would result in the ARB not meeting the 2020 targets in the AB 32 Scoping Plan and in Governor Schwarzenegger's Executive Order S-01-07. Staff did take under consideration delaying the LCFS program pending the development of regional GHG programs like the one under development by the Western Climate Initiative (WCI), but concluded that delaying the LCFS would also fail to meet the same goals of AB 32 and EO S-01-07.

California is currently developing a Cap-and-Trade regulation. The regulation must be adopted by January 1, 2011, and the program itself must be effective in 2012. As noted in the AB 32 Scoping Plan, the LCFS is scheduled to be incorporated into ARB's Cap-and-Trade program by 2015.

California, through the WCI, is working closely with six other western states and four Canadian provinces during the development of ARB's Cap-and-Trade program. The goal is to design a regional Cap-and-Trade program that can deliver GHG emission reductions within the region at costs lower than could be realized through a California-only program.

The WCI's Complementary Policy Subcommittee has categorized the LCFS as the highest priority for further evaluation. The subcommittee intends to determine whether the policy should be recommended for broader adoption and/or harmonization. WCI's commitment to harmonization means that California would not be disadvantaged by adopting the LCFS prior to potential action by other WCI partners. Therefore, to meet the AB 32 and EO S-01-07 goals, staff rejected delaying the adoption of the LCFS pending WCI action.

Finally, the Cap-and-Trade program has a fundamentally different approach to the LCFS and is expected to be designed to complement the LCFS. That is, the Cap-and-Trade program would not necessarily reduce the CI of transportation fuels, which is a key objective of both the AB 32 Scoping Plan and Governor Schwarzenegger's Executive Order S-01-07.

I-54. Comment: CARB failed to review other alternatives, as required by California Government Code 11346.9, which provide quantifiable reductions in greenhouse gas emissions and are currently available to the end user at a lower cost. There are numerous ways to reduce GHG emissions from diesel users. Energy efficiency measures are the single-most cost-effective measure, provide

immediate and significant reductions in GHG emissions. The least costly measures were not evaluated and the LCFS provides little if any GHG reductions in first years post-adoption at a very high cost to the end-user. (IWLA)

Response: We did evaluate alternatives to reducing GHG emissions from transportation fuels, but found no other alternative that would achieve the equivalent amount of GHG emissions reductions expected from the LCFS. The LCFS is expected to achieve nearly 10 percent of the total GHG reductions needed to meet the overall 2020 targets in AB 32. Without these reductions, the ARB would be unable to meet the GHG reduction targets set forth in Governor Schwarzenegger's Executive Order S-01-07 and the AB 32 Scoping Plan.

We considered an economic assessment of two alternative approaches to the proposed regulation. We considered a "do not adopt" alternative, where only the federal RFS2 would be in effect, but this would achieve only 30 percent of the GHG reductions projected under the LCFS program. We rejected this inadequate alternative.

We considered a second alternative of requiring a "gasoline-only" LCFS, excluding any requirements on diesel. Since diesel accounts for approximately 20 percent of the total liquid transportation pool, excluding it would achieve only 80 percent of the GHG reductions projected under the LCFS program. We rejected this inadequate alternative.

We agree that energy efficient measures are important components to reducing GHG emissions from the transportation sector. AB 375, which addresses local land use issues, and the Pavley regulations are some examples of these types of measures. However, the LCFS is an additional measure that is needed as well, and one of several transportation-related measures identified in the AB 32 Scoping Plan.

Administrative Procedures Act

I-55. Comment: The cost impact provided by CARB does not meet the requirements of the Administrative Procedures Act. Forcing fuel standards within an 18-month lead time creates provider cartels, and cartels, by their very nature, exploit the end-users. If the only compliance path available is a variance or "tax" on each gallon of fuel sold, CARB must be transparent and include this as part of the rulemaking. With no diesel compliance path in sight, the only option is a variance, which is a known price per gallon of fuel sold in California. Neither the variance cost impact nor the premium cost for a renewable or biodiesel blend is reflected in this rulemaking. (IWLA, IWLGRP)

Response: The California diesel fuel regulation, adopted in 1988 and amended in 2003, includes a provision for a refinery unable to produce sufficient California diesel due to unforeseen circumstances beyond its control (such as a refinery accident), to request a temporary variance from ARB to produce or import diesel that does not meet ARB's requirements to ensure minimum adequate diesel supplies in California. In most cases, ARB required refineries receiving a variance to pay a mitigation fee for each

gallon of non-complying fuel produced to ensure that they did not accrue a financial benefit from selling fuel that is cheaper to produce than California diesel. This type of variance, however, is not included in the LCFS. Consequently, no variance cost impacts were included in the LCFS economic analysis. The LCFS does, however, allow regulated parties to buy credits to comply with a particular year's CI standard, although the cost of these credits is unknown at this time. We estimated renewable and biodiesel fuel cost in the economic analysis. Staff will be presenting fuel specifications for biodiesel and renewable diesel to the Board for approval next year, and the cost of producing those fuels will be further analyzed in the rulemaking process for those fuels. Finally, the requirements in the LCFS for the early years (2012-2014) are modest; therefore the necessary alternative fuels will be phased in over time.

I-56. Comment: CARB should develop a rulemaking that complies with the Administrative Procedures Act and that can be adopted by the Office of Administrative Law based on completeness. (IWLA, IWLAGRP, WSGM)

Comment: Relevant economic effects on business from the regulation are not addressed. Government Code Section 11346.3 requires a broad assessment of the potential for adverse economic impacts on "business" – not simply California businesses and not simply limited impacts. The staff report limits, without justification, the entire analysis of economic effects to the "cost effectiveness" and "job growth" aspects of the regulation. (GE3)

Response: Section 11346.3 of the Government Code requires State agencies to assess the potential for adverse economic impacts on *California* business enterprises and individuals when proposing to adopt or amend any administrative regulation. The assessment must include a consideration of the impact of the proposed regulation on California jobs, business expansion, elimination or creation, and the ability of California businesses to compete with businesses in other states. We fulfilled these requirements and presented our analysis in Chapter VIII of the Staff Report.

Incomplete Analysis/Postponement

I-57. Comment: And it looks like you're still not doing the analysis necessary to truly figure out what the LCFS will cost, whether the technology is or will be available, and what the impacts will be on the environment and public health. (CMCC)

Comment: We're very concerned that the adoption of the LCFS today is premature and could result in significant fuel supply cost and quality problems that will harm California's economy and jeopardize success of the program. We believe the LCFS has not been adequately evaluated in terms of availability of low carbon fuels, the impact on energy prices, and environmental impacts. (CMTA)

Comment: Staff's economic analysis is inadequate. ARB staff is not sufficiently trained in economics in order to perform an appropriate analysis. The analysis uses optimistic and unrealistic assumptions. Stakeholders need to see the

underlying work that leads to ARB's assumption that low carbon fuels that do not now exist will be available at lower costs than conventional fuels. (WSPA1)

Comment: Additional work should be done to accurately determine the effects this regulation will have on the economy. (CSC)

Comment: Future research should attempt to understand how to minimize the intended and unintended costs of regulation. (CSBR2, CSBR3)

Comment: We also worry about economic issues. During the Scoping Plan process, this Board promised the community it would thoroughly analyze each individual policy proposal under AB 32. We hope you will take that promise seriously and insist that your staff do everything required to give you a complete, accurate picture of the economic, environmental pros and cons before you make a final decision on the low-carbon fuel standard. (SFVMAPA1)

Comment: Can you tell us more today than you could last month about what this will cost our communities in terms of annual energy bills, costs per gallon of gas, and how those numbers were calculated? We want the low carbon fuel standard to succeed, but we don't want it so badly that we're willing to accept the policy that has pushed through without responsible research and evaluation. (SFVMAPA2)

Comment: We don't know if the fuels, additives or technologies will be available, or even invented or perfected, to meet the requirements of this standard. We don't know what it will cost. (SDCHCC, HCCCCC)

Comment: We have serious concerns over the lack of a complete economic analysis. (TESORO2)

Comment: We are disappointed that, as was the case with the approval of the Scoping Plan last year, you are preparing to adopt a rule based on incomplete economic analysis. (CBCOC1, CBCOC2)

Comment: SB 295 is being proposed to slow down the implementation of AB 32 until proper studies are done and an economic analysis is done properly. (CBCOC2)

Comment: Staff's economic analysis is grossly deficient. The economic analysis of this rule is playing out as a repeat of the Scoping Plan analysis: after-the-fact justification of decisions that have already been made, instead of front-loaded analysis that informs the Board and public of significant impacts of different program design options. (AB32IMPG1)

Comment: The economic analyses and the associated technological feasibility studies should "drive the process". We believe these assessments should be the

basis for policy and regulatory decisions and should be completed and reviewed before regulations are proposed and adopted. (CONOCO)

Comment: In particular we're worried, since a lot of our businesses are heavy diesel fuel users engaged in agriculture and trucking, that the diesel component of this rule will cause far more problems than it will solve. If this rule is not adopted until all the unanswered questions can be worked out, it won't mean the end of the fight against global warming. If it's adopted too soon, though, it will mean the end of more California small businesses and jobs. Please delay action on this rule until these important issues have been resolved. (SJCHCC2)

Comment: Let's take the time to get all the facts and do it right. Don't overlook the necessary balance between the environment and the economy. If we are going to be effective, we need to do it right. We respectfully ask that you postpone taking action on this item until the true costs are known, considered, and undergo reasonable public scrutiny. (CHCOC3, CHCOC2)

Comment: This should be postponed so you can really look at some of these costs. (CHCC2)

Comment: We already have the cleanest gasoline in the country, surely we can afford to take the time necessary to make sure a new fuel standard doesn't cost billions and - in cooperation with the rest of the country and the world - will actually fulfill its mission to reduce global warming. Please postpone your decision until you - and the public - have all the facts. (SJCHCC3)

Comment: Now you're considering the first major rule under AB 32 and it looks like you're still not doing the analysis necessary to truly figure out what the Low Carbon Fuel Standard will cost, whether the technology is or will be available, and what the impacts will be on the environment and public health. And we can't afford to rush into this rule without proper study. Please continue this item until such time as your staff has answered the critical questions about cost and other impacts. (SVHCC)

Comment: The LCFS is one of the largest components of AB 32 and likely to be one of the most expensive. Yet your staff has failed to complete critical economic, technical and environmental studies necessary to successfully develop and implement the rule. Still, they tell us it won't cost much, and seem to think that by decreasing the development of new fuels and vehicles will make it happen despite daunting scientific, technological and cost hurdles. As a small business owner who supports AB 32, I ask that you take the time to exercise due diligence before proceeding with this rule. (CON10U)

Comment: We urge you to postpone taking action on this item, until the necessary analysis has been fully completed and the rule can be fine-tuned to reflect economic and technical reality. (NFIB)

Comment: I suggest you hold off on your decision until you can tell the public what this is going to cost us and can assure us there will be a material reduction in global warming for the money. (CHCC1)

Comment: The economic environment must be as healthy as the physical environment. You can't have one without the other. That's why I've come here from Oakland today to ask you to take more time to fully evaluate the Low Carbon Fuel Standard. The purpose of the standard is to reduce carbon emissions from transportation fuels, which contribute to global warming. But it appears that the true costs of this policy have not been thoroughly analyzed, and the necessary fuels are not developed and/or available. (CBCOC1)

Response: We believe we have performed a complete economic analysis. We met the requirements of AB 32 by relying upon the best available economic and scientific information and by assessing the existing and projected technological capabilities to reduce greenhouse gases. We believe the economic analysis used reasonable assumptions and projections into the future. By approving the LCFS for adoption—and not postponing its consideration—the Board agreed with staff that the economic analysis was complete and thorough. However, we understand that the economic analysis of the LCFS is greatly affected by future oil prices and the actual production costs and timing of lower-carbon-intensity alternative fuels. Economic factors, such as tight supplies of lower-carbon intensity fuels or a lengthy economic downturn keeping crude demand and hence prices down, could result in overall net costs, not savings, for the LCFS.

Updating the economic impacts of implementing the LCFS will be part of the periodic reviews of the LCFS program, which are scheduled to be completed by January 1, 2012, and January 1, 2015. Any unintended economic impacts from implementing the LCFS will be evaluated and addressed at that time.

I-58. Comment: Further analysis by ARB should include costs and prices of biomass-based energy carrier, local costs of alternative energy sources, costs across the supply chain, opportunity costs of land, labor, and water used, costs and prices of biomass-based energy carriers; current taxation and subsidy situation in light of future bioenergy scenarios; economic and social costs and benefits of different types of support: subsidies, import tariffs and other import restrictions, and consumption mandates; net loss in government revenue and what other government programs will be cut as a result, and alternative uses of government subsidies. (CERA2)

Response: We took into account all costs associated with producing and distributing lower-CI fuels when calculating the cost of these fuels. The production and distribution costs for the lower-CI liquid biofuels included the capital costs for building the fuel-manufacturing facility, the operating or production costs to produce the specific fuel, the costs for purchasing the feedstock material for the fuel, and the costs for storing,

transporting, and distributing the fuel. A summary of these fuel costs are included in Table VIII-8 on page VIII-17 of the Staff Report. In addition, we applied the alternative-fuel tax incentives to the cost-effectiveness analysis and analyzed the fiscal impact those incentives would have on government revenue. We cannot speculate on what other government programs would be impacted by these tax credit expenditures or other ways the government could be spending these subsidies, as these decisions are made by elected officials.

I-59. Comment: Further analysis by ARB should include economic and social costs and benefits of different types of support. (CERA2)

Response: We conducted the economic analysis on a cost-of-compliance basis—which is an analysis that is consistent with other ARB regulations—not on a social basis. Congress has chosen to create tax credits for alternative fuels in order to promote their commercialization and make them more competitive with traditional transportation fuels. On what those tax dollars would otherwise be spent would be speculative.

Need for Peer Review of Economic Analysis

I-60. Comment: We believe an independent third party economist, or better yet a team of economists similar to what the state did for the AB32 Scoping Plan, is needed to assess the LCFS. In addition, we request that this peer review be conducted well in advance of the hearing so there can be adequate public review and discussion of the review contents. The team of peer reviewers should also be asked to present a summary of their findings at the adoption hearing. The need for such reviews highlights the fundamental problem posed by the lack of sound economic and feasibility analysis. (WSPA1)

Response: We solicited independent peer review of the proposed LCFS to comply with Health and Safety Code section 57004 and to help inform ARB's analysis of the LCFS. The reviewers were to address five specific areas related to the LCFS development including the economic analysis. ARB received comments from four reviewers. These comments were posted in advance of the Board hearing on the LCFS rulemaking webpage: (<http://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=lcfs09>). All of the peer review comments on the LCFS are responded to in Chapter N in this FSOR, including those pertaining to the economic analysis. Regarding the completeness of the economic analysis, please refer to the response to Comment I-57.

Industry-Funded LCFS Economic Study

I-61. Comment: A new study of your staff's analysis says this fuel standard will cost almost \$4 billion a year. It says your staff's assumptions were based on theories, not real data experience. (CMCC, CBPA, CBCOC2, WEITZMAN1, WSPA1, SVHCC, CBCOC1, CHCOC3, CHCOC, NFIB, CMTA, CONOCO)

Response: The Sierra Research study (study) to which the commenters refer makes several assumptions dissimilar to those in our economic analysis:

- a. Crude prices were kept at \$66/bbl throughout the 10-year period, which is contrary to CEC and Energy Information Administration (EIA) estimates. We used forecasts of crude oil prices (\$66 - \$88 per barrel) from the CEC 2007 Integrated Energy Policy Report (IEPR), which is consistent with the AB 32 Scoping Plan. The EIA recently published estimates for crude prices at \$78 - \$116 per barrel for 2010 - 2020. In the draft 2009 IEPR, CEC is currently estimating crude prices of \$73 - \$86 per barrel for 2010 - 2020.
- b. The study used \$3.98 per gge for cellulosic ethanol production costs. This cost estimate is based on a capital cost of \$1.94 per gge from a new joint study by NREL, Iowa State, and ConocoPhillips (which includes offset credits and installation of an SCR system), a feedstock cost of \$1.08 per gge, a production cost of \$0.66 per gge, a co-product credit of \$0.14 per gge, and distribution and marketing costs of \$0.44 per gge. We estimated the cost of production of cellulosic ethanol based on published studies by NREL, the Department of Energy (DOE), and others. According to the 2007 NREL State of Technology Study, using a feedstock of corn stover, the cost of cellulosic ethanol production is estimated at \$2.43 per gal (\$3.60 per gge), with a DOE target cost of \$1.33 per gal (1.97 per gge) for 2012. We used \$1.93 per gal (\$2.86 per gge) for the cost of cellulosic ethanol for 2012, which is conservative compared to the DOE target cost.
- c. The study included the marginal cost of the ZEVs. The LCFS does not mandate ZEVs. The numbers of ZEVs on the road will depend on two factors: a more stringent ZEV mandate from the Board, and a public acceptance of the ZEV technologies (PHEVs, BEVs, FCVs). If California mandates the deployment of additional ZEVs, those costs should be borne by the ZEV program, not the LCFS. Otherwise, additional ZEVs will be on the road due to public preference for these vehicles.
- d. The study did not take into account the tax incentives for biofuels. We conducted the economic analysis on a cost-of-compliance basis—which is an analysis that is consistent with other ARB regulations. Congress has chosen to create tax credits for alternative fuels in order to promote their commercialization and make them more competitive with traditional transportation fuels. Historically, these tax credits have been renewed before expiration; we assume this will continue until biofuels become cost-competitive with petroleum-based fuels.

I-62. Comment: It is very important to note that Dr. John Reilly, the only peer reviewer who holds a PhD in Economics, made many of the same statements as Sierra Research. Although staff concluded that none of the peer reviewers provided comments that would require major modifications to either the proposed rule or the analysis used to support the proposal, we do not believe this to be an

appropriate conclusion, given statements by Dr. Reilly. For example, “The economic analysis was done incorrectly. It does not meet technical standards of economics. The baseline assumptions are mutually inconsistent,” and, “the estimate of economic impact on the State of California is done incorrectly because the tax and tax revenue implications are dealt with inappropriately”, and, “Thus these tax expenditures should be added on as a cost to Californians, and the expenditures should be increased by an amount to account for the deadweight loss associated with tax collections”, and, “another critical issue is the accounting of only fuel and administrative costs and not of vehicle costs.” (WSPA1, WEITZMAN2, WEITZMAN1, CONOCO)

Response: We conducted the economic analysis on a cost-of-compliance basis. Therefore, it is appropriate to include tax credits in the economic analysis. Congress has chosen to create tax credits for alternative fuels in order to promote their commercialization and make them more competitive with traditional transportation fuels.

As also previously stated, we did not consider the vehicle costs in the analysis because the LCFS does not mandate deployment of specialized vehicles—such as plug-in hybrids, battery-electric vehicles, and flexible-fueled vehicles. The number of these vehicles on the road will depend on two factors: a more stringent mandate by the Board and/or a public acceptance of these vehicles. The eight illustrative compliance scenarios merely used a variety of vehicle-deployment possibilities.

Finally, when Dr. Reilly stated, “The economic analysis was done incorrectly. It does not meet technical standards of economics. The baseline assumptions are mutually inconsistent,” he was addressing a broader issue with the LCFS. In his report, Dr. Reilly indicated that more extensive economic analyses of other approaches for reducing greenhouse gases from vehicles and fuels, such as carbon fees and cap-and-trade program, should be conducted prior to another jurisdiction adopting an LCFS. He further commented that such an assessment would likely show that an LCFS was a more costly method to reduce GHG emissions than other more economically efficient approaches. We agree with Professor Reilly’s opinion that the LCFS needs to be assessed in light of other options. We believe that an LCFS is most effective when it is combined with other programs to reduce GHG emissions from the transportation sector and operates under a broad cap on emissions. We are not advocating the proposed LCFS be pursued as a stand-alone program in other jurisdictions.

I-63. Comment: Our contractor highlighted the following: “three issues that CARB needs to consider carefully in performing its economic analysis of the Low-Carbon Fuel Standard (LCFS): uncertainty, the appropriate baseline against which to measure, alternative scenarios necessary to understand the cost of the LCFS. The economic impacts of the LCFS could be among the most significant of any element of CARB’s AB 32 Scoping Plan. Moreover, it is possible that adjustments to the design of the LCFS could significantly reduce its cost and the economic risks that it poses. Therefore, sound and comprehensive economic

analysis is immensely important in order to inform CARB's decisions in implementing the LCFS." (WSPA1)

Response: We believe we have performed a complete economic analysis. We met the requirements of AB 32 by relying upon the best available economic and scientific information and by assessing the existing and projected technological capabilities to reduce greenhouse gases. We believe the economic analysis used reasonable assumptions and projections into the future.

In regards to uncertainty, we conducted sensitivity analyses for key parameters, including crude prices, feedstock costs, and real interest rates. (See VIII-34 – VIII-36 of the ISOR.) These analyses showed that the LCFS is cost-effective over a wide range of assumptions.

We created a baseline scenario for the LCFS regulation from which the emission reductions and cost effectiveness of the LCFS regulation were estimated. We assert that the baseline scenario reflects the successful implementation of the Scoping Plan measures that impact the amount of transportation fuels and resultant GHG emissions expected in California between 2010 and 2020. These regulations and programs include: the ARB Zero Emission Vehicle (ZEV) regulation, the federal Corporate Average Fuel Economy (CAFE) program, the Pavley regulation, and the federal Renewable Fuel Standard (RFS).

A key component of the economic analysis is the consideration of alternative scenarios of compliance. The scenarios are illustrative examples on how to comply with the LCFS regulation. The proposed regulation provides flexibility for the regulated parties. The regulation is performance-based, and fuel providers have several options. First, they may supply a mix of fuels above and below the standard that, on average, equal the required carbon intensity. Second, they can choose to only provide fuels that have lower carbon intensity than the standard. For example, they may blend low carbon ethanol into gasoline, or renewable diesel fuel in diesel fuel. Third, they may purchase credits generated by other fuel providers to offset any accumulated deficits from their own production. For example, a fuel provider may choose to purchase credits generated from another fuel provider that has banked credits from using electricity in a plug-in hybrid vehicle. Fourth, a fuel provider may bank excess credits generated in a previous year and use those credits when needed. As the objective is to ensure lower carbon intensity fuels are created and used in the California fuels market, the LCFS does not allow the use of credits, or offsets, generated from outside the transportation fuels market.

I-64. Comment: Our economist highlights that ARB's initial economic analysis for the LCFS rule should include the following:

- a. Final LCA numbers prior to completion of the economic analysis;
- b. Identification of tonnage reductions that are attributable to the gasoline program, and reductions attributable to the diesel program;

- c. Cost estimates (in \$/ton) for each of these two sets of reductions, for each year of the program;
- d. Comparable estimates for cost of reductions if there was only one combined gasoline diesel reduction requirement;
- e. For the proposed reductions for the first three years of the program before the first review, ARB must determine whether the proposed reductions can be achieved with currently available materials and technologies, and the cost estimates based upon those materials and technologies; and,
- f. For each periodic review, necessary adjustments to lifecycle analysis are made, and the upcoming four years' proposed reductions are tested for feasibility based upon then currently available materials and technologies. (WSPA1)

Response: Lifecycle Analysis (LCA) numbers will be continually updated as better data become available. This is an important element of the regulation.

The cost and benefit estimates for both diesel and gasoline of the LCFS are contained in Appendix G of the Volume II of the ISOR.

The LCFS includes two separate standards; one for gasoline and the alternative fuels that can replace it, and one for diesel fuel and its replacements. A gasoline standard only approach has been advocated by various stakeholders to allow for a simpler implementation of the regulation in the early years. We do not support this approach. We believe that a comprehensive approach from the beginning will allow for the development of a more robust credit market and will provide greater certainty on future expectations. Fuel producers will need to consider overall approaches to providing low carbon transportation fuels. Given the fact that the compliance requirements are substantially less in the early years should provide fuel producers adequate time to develop appropriate compliance options. In addition, because diesel accounts for approximately 20 percent of the total liquid transportation pool of California, failure to include diesel will result in a loss of approximately 20 percent of the LCFS benefits. Therefore, this alternative would not meet the requirements of AB 32 and was deemed to be not as effective as the proposed action. From an economic perspective, our analyses of the three illustrative diesel scenarios estimate that, with the tax incentives in place, lower-CI alternative diesel fuels result in an overall savings relative to the base case of strictly petroleum-based diesel fuels. Excluding diesel from the LCFS will not only forgo 20 percent of the GHG emission reductions from the proposal, but will also forgo possible overall savings to the State. Therefore, the LCFS is preferred over the gasoline-only alternative.

ARB's commitment to review the LCFS in 2011 and 2014 will allow potential issues that may arise to be addressed.

Support for our Economic Analysis

I-65. Comment: I'd like to speak today in strong support for the California low carbon fuel standard. Moving California to reduce the carbon intensity of our transportation fuel mix as well as our vehicle pool is a critical component towards getting our state to reduce its overall emissions of greenhouse gases. However, reducing our carbon footprint will require both a significant undertaking and undoubtedly require both initial and sustained capital investments. While achieving the 2020 goal will require some expenditure, the LCFS should be seen as an investment. That investment will yield returns through fuel diversification, increasing resilience to fuel price shocks and swings, independence from foreign fuel sources, development of new businesses and general economic growth. EDF, like many environmental advocates, has already -- who have already spoken today, we understand the concerns and the questions being offered by businesses who have talked to us about their inability to understand how the fuel price swings will be moderated by the LCFS or who have concerns about increasing prices overall. Counter to some of the claims that we've heard though, we believe that the LCFS is an important hedge against higher fuel prices. That is likely increases in long-term crude prices coupled with even better and cheaper alternative production methods will make carbon fuels more affordable than gasoline. One of the core benefits of the LCFS is that it's a system of tradable and bankable credits to provide compliance flexibility, cost containment and robust incentives for early action. By creating market incentives early, by back-loading the compliance obligations and providing early incentives for people to innovate, we should be seeing longer term smoothing of cost burdens and positive pressure on innovation. We've analyzed a lot of the economics of the LCFS. We see it as a cost-effective approach. We see that the staff has, where possible, gone conservative with some of the benefits and we really appreciate that and we thank the staff for all their hard effort and we strongly support the low carbon fuel standard. (EDF3)

Comment: The LCFS framework—a performance standard not a technology mandate—gives fuel producers freedom to choose compliance strategies that best suit their production plans. This compliance flexibility, together with a market-based system, allows for credit trading, which provides additional flexibility and lowers the cost of compliance. It also provides regulatory certainty for fuel suppliers, innovators, and investors in emerging low carbon fuel technologies without picking winners. The LCFS will spur innovation and economic growth in California. Investment in clean fuel technologies will keep dollars here at home and create local jobs, while contributing to both energy and climate security. Consumers will be less vulnerable to petroleum market swings, and will benefit from more stable fuel prices. (BAMCGRP)

Comment: We are encouraged that California and our region are pursuing similar approaches, since a consistent approach to the LCFS will help us all achieve the greenhouse gas emission reductions needed from the transportation sector in the most cost -effective and expeditious manner. As proposed, California's LCFS is appropriately designed to let fuels compete in the

marketplace, rather than picking winners. This approach will spur the creation of a new generation of clean transportation fuels and technologies by providing incentives for investing and marketing the lowest carbon fuels. Like you, we believe that a properly designed LCFS will promote much-needed economic development, jobs, and long-term investment in our low carbon future. (MADEP)

Comment: The economic analysis by CARB is conservative. Using any number of reasonable forecasts of crude oil prices, Californians will stand to benefit from significant fuel cost savings due to the LCFS. The LCFS will help diversify our fuel supply and help protect consumer pocketbooks from oil price swings. Future cellulosic ethanol feedstock costs are difficult to forecast but CARB has relied on the best-available estimates including DOE estimates. CARB has been reasonable to account for existing government policies that already mandate biofuels nationwide. Doing so prevents falsely double-counting for both monetary costs and benefits that are already accounted for by the federal RFS program. While the Pavley rule will improve the performance of conventional vehicles, CARB has already accounted for this explicitly in adopting conservative energy efficiency ratios. There is no reason to believe that plug-in electric vehicles or fuel cell vehicles will not improve as fast as (or faster) than their mature, conventional technology counterparts. The LCFS will help biofuels get on the right path by incentivizing the types that avoid indirect land use change. The California LCFS will not damage the ethanol industry because national law mandates a market for corn ethanol that will grow 2.5 times over the next six years to 15 billion gallons. Instead, the LCFS helps to even distinguish between better, more efficiently produced corn ethanol. (NRDC3)

Comment: We support the LCFS because it will spur innovation and economic growth in our state and communities, keeping dollars here at home and creating local jobs, while contributing to both energy and climate security, and avoiding price swings. All Californians will benefit from fuel price stability. California has already demonstrated it can save energy while growing the economy through its groundbreaking energy efficiency and green tech policies. (COF)

Comment: CEERT strongly supports the low carbon fuel standard. There have been several speakers who voiced concerns over the cost exposure that they feel they might be exposed to with this regulation. But what I would like to remind people about is only last July we were looking at nearly \$150 a barrel oil. That situation has backed off because of the current financial crisis. Exploration and development has also drawn back, and once the economy recovers, we are going to see a return to exponential increases in oil prices, along with a super-spike scenario overlaid on top of that. And at some point, we have to move away from petroleum to other alternatives. If we don't start now, when will we start? So for both our battle against the emissions associated with fossil fuels for transportation and to get us to other alternatives that are more economically sustainable, this standard is very important. (CEERT1)

Comment: Contrary to claims by the oil industry, the LCFS would benefit the economy by helping protect consumers from high oil prices by forcing oil companies to diversify our fuel supply that is currently 97 percent dependent on petroleum. (FORMLETTER3)

Comment: We also support the LCFS because it will spur innovation and economic growth in our state and our communities, keeping dollars here at home and creating local jobs, while contributing to both energy and climate security, and avoiding fuel price swings. All Californians will benefit from fuel price stability. (CCCC)

Comment: Advancements in technology and growth of new technologies will create jobs and competition in the energy sector. California, as always has to be the leader. Please support this proposal. (POUSMAN)

Comment: We also support the LCFS because it will spur innovation and economic growth in our state and our communities, keeping dollars here at home and creating local jobs, while contributing to both energy and climate security, and avoiding fuel price swings. All Californians will benefit from fuel price stability. (COF)

Comment: New wealth industries are vital to the reconstruction of America during these trying times, given their economic multipliers (generally more than three, whereas service industries are limited to one or a little more). They create new basic industries and quality jobs; they have ready markets-many are "shovel ready", they encourage "positive nation-and community-oriented" consumption and, contribute to national, energy, homeland, economic, and environmental security while reversing greenhouse gas build-up. (BCC1)

Comment: I would like to approach the matter from a different perspective-the value of the agriculture and forestry sectors to the California, the US and the world's economy today and in the years ahead. (BCC1)

Response: These comments are in support of the LCFS. The LCFS is designed to reduce California's dependence on petroleum, create a lasting market for clean transportation technology, and stimulate the production and use of alternative, low-carbon fuels in California. Governor Schwarzenegger has identified all of these outcomes as important goals for California.

Overall Savings

I-66. Comment: Do you really think that your report in real life is going to save us \$11 billion by 2020 and \$3.4 billion after that annually? If so why hasn't it been done? Anyone who can make \$3.4 billion annually would get right down to business, but that's not the case. (WEITZMAN2)

Response: The estimated \$0 to \$11 billion savings from 2010 - 2020 is based on several assumptions:

- a. Crude prices will be \$66 - \$88/bbl during this time period (based on 2007 IEPR);
- b. The cost of producing cellulosic ethanol will decline as technology improves and the industry matures (based on National Renewable Energy Laboratory [NREL] estimates); and
- c. Current tax incentives for biofuel production will be renewed throughout this timeframe.

Currently, there are pilot plants producing cellulosic ethanol and plans to build commercial plants. Furthermore, hundreds of millions of dollars are being spent for research on biofuel production. The recent economic slowdown, coupled with tight credit and lower crude prices, have slowed current progress; however, as the economy improves and crude prices climb again, market forces will be more favorable for the commercial production of biofuels. Meanwhile, the requirements of the LCFS for the early years (2011 – 2014) are modest, allowing time for the necessary biofuel production facilities to come online.

We assume that the commenter's claim of annual savings of \$3.4 billion beyond 2020 is based on an extrapolation of the year 2020. If crude prices remain at levels of \$90/bbl or more, and the above assumptions remain true regarding declining biofuel production costs and continuing tax benefits, we estimate that indeed additional savings will be realized beyond 2020. These savings may or may not be passed on to the consumers.

I-67. Comment: If California is to save \$3.4 billion a year then energy on a gasoline equivalent per gallon should go down by at least 20 cents a gallon? Or is there another plan? (WEITZMAN2)

Response: We estimated \$0 - \$11 billion savings from 2010 – 2020 by including savings from both the gasoline and diesel pathways. As stated in the ISOR, the savings may either be realized by the biofuel producers as profit, or some of the savings may be passed on to the consumers. Should annual savings be \$3.4 billion after 2020 (see response above) and all savings were entirely passed on to consumers, 20 cents per gallon price decline at the pump would not be an unrealistic figure. However, much of that savings could be kept as profit by the biofuel manufacturers.

I-68. Comment: If the fuels used under the LCFS were actually less expensive than the petroleum fuels they are replacing, then there would be no need to enact the LCFS, as the free market would ensure that the less expensive fuel was consumed. Unfortunately, this is not the case. (ATA)

Comment: A key issue in the measurement of the LCFS's economic impact is the determination of an appropriate baseline of how transportation fuel markets would evolve in the absence of the LCFS. It is critical that this baseline be

consistent with CARB's projections of fuel prices. If CARB believes that low-carbon fuels will be less costly than, or as costly as, conventional fuels even in the absence of the LCFS, the baseline should reflect that low-carbon fuels would be adopted even in the absence of the LCFS. Alternatively, if CARB does not believe this would be an appropriate baseline, it needs to offer a rigorous assessment of why low-carbon fuels would not be adopted in the baseline even if they are less costly than conventional fuels. (WSPA1)

Response: For biofuels to be competitive with petroleum-based fuels, technological advances in the production of biofuels must occur, and the cost of petroleum must be sufficiently high. Hundreds of millions of dollars are currently being spent for research on biofuel production, including constructing pilot plants and commercial-sized plants. These efforts are supported by tax credits and grants from the federal government. The market alone will not spur the necessary innovation today to produce new biofuels, such as cellulosic ethanol.

For market-based incentives to be effective, the price of crude oil will have to remain high for an extended period of time. We believe that, with a worldwide economic recovery and a diminishing supply of crude oil, crude prices will rise, making alternative fuels more competitive.

I-69. Comment: Assessing the cost of the LCFS relative to the business-as-usual baseline should be a key element of CARB's analysis. (WSPA1)

Response: The business-as-usual baseline is included in the economic assessment of LCFS. The cost effectiveness data that was presented in ISOR is based on the cost of LCFS minus the cost of a baseline case. The data can be found in VIII-25 to VIII-33 of ISOR (Volume I) and also Appendix G (Volume II).

I-70. Comment: While Staff asserts that the shift in capital from the petroleum sector to the agricultural, chemical, electrical, and natural gas sectors is a good thing, it fails to account for any costs associated with such shift which are bound to occur in the short term due to disruptions in the demand supply balance for capital between the sectors. (CSBR2, CSBR3)

Response: We realize that available credit for investment has been recently more difficult to acquire. However, as the economy improves, funding for capital projects will become more available. Since the requirements of the LCFS are modest in the early years, and with the petroleum companies investing in biofuel producers, we do not foresee a disruption between the sectors for available capital.

Uncertainty

I-71. Comment: The implications of this uncertainty for the cost of the LCFS are not symmetric. If conventional fuels turn out to be less costly or if low-carbon fuels turn out to be more costly than anticipated, then the LCFS may be far more

costly than CARB projects. On the other hand, if conventional fuels turn out to be more costly or if low-carbon fuels turn out to be less costly than anticipated, the LCFS's target may be met even without the LCFS in place. (WSPA1)

Comment: It should also be noted that the estimates of alternative fuels costs, including our own, are based on paper studies that assume economies of scale yet to be demonstrated in practice. The economic analysis in the Initial Statement of Reasons (ISOR) fails to account for the uncertainty associated with such studies. This is especially a concern given that a study published subsequent to the preparation of the ISOR projects higher costs than earlier studies. (WSPA1)

Comment: Because the economic assessment that CARB has conducted depends on the accuracy of the assumptions made, the economic impact conclusions drawn are also flawed. The citizens of California are at risk of significant negative economic consequences from the implementation of this rule. Recognition of the uncertainty of the assumptions made needs to be factored into CARB's economic analysis such that citizens can recognize the economic risk to the state and them personally if the assumptions are incorrect. (ILCORN)

Response: As stated in previous responses, we based our economic analysis on several key assumptions—assumptions that were collected from several sources, including the California Energy Commission and the NREL, among others. By following this approach, we used the best available information. We also stated that, if these assumptions ultimately prove to be incorrect (i.e., there are actually lower crude prices and higher biofuel production costs), the LCFS could have net costs, not net savings.

To account for uncertainty, we conducted sensitivity analyses for key parameters, including crude prices, feedstock costs, and real interest rates. (See VIII-34 – VIII-36 of the ISOR.) These analyses showed that the LCFS is cost-effective over a wide range of assumptions.

The regulation requires ARB to conduct reviews of the LCFS in 2011 and 2014. These reviews will include assessing the cost and availability of alternative fuels. Should the LCFS be determined to be costly to California's economy due to unrealized assumptions or prevailing economic conditions, staff may return to the Board to revise the regulation.

Regarding the study to which one commenter refers—one published subsequent to the preparation of the ISOR—we address that study in the response to Comment I-61.

I-72. Comment: Unfortunately these proposed rules, if implemented, may not decrease CO₂ emissions as predicted, may cost the citizens of California further economic pain and suffering, may increase our dependence on imported fuels and harm the economy of the agricultural sector in the U.S. resulting in higher food, fuel, and feed costs. (ILCORN)

Response: By lowering the carbon intensity of transportation fuels, the LCFS will reduce CO₂ emissions. We have taken into account the effects of other transportation-related measures that will impact fuel use, such as Pavley regulations and SB 375, so that no double-counting of benefits has occurred. Our economic analysis indicates that the LCFS may either result in overall cost savings or be cost-neutral to the consumer, although some costs may occur if crude prices decline and alternative fuel production costs are higher than estimated.

One of the key advantages of the LCFS and the federal RFS2 is that it reduces our dependence on foreign oil. Although some of the alternative fuels may be imported—Brazilian sugarcane, for example—most of the fuels will be produced in the United States. Finally, by including indirect land use change in the lifecycle analysis of biofuels, the LCFS ultimately discourages food-crop-based biofuels and encourages those that do not have such land use impacts, such as waste products: biomass, yellow grease, and tallow.

I-73. Comment: ARB's current analysis of fiscal impacts seems to be focused on the out years of the program (i.e., towards 2020). Given this is the most speculative timeframe in terms of the nature and availability of the required technology, it is relatively easy for staff to postulate on successful scenarios for complying with LCFS. (WSPA1)

Response: If the economic analysis seems more focused on the latter years of the regulation, it is simply because the LCFS standards are back-loaded: more GHG reductions are required during the last five years than the first five years.

I-74. Comment: We urge CARB staff to carry out a rigorous analysis of the feasibility and cost of the LCFS that goes beyond supporting pre-existing reduction targets. The results of the feasibility and cost analyses should inform the setting of gasoline and diesel targets that potentially differ from current targets. The analysis should also include, as an option, a diesel AFCl reduction target of five percent along with an analysis of the cost, benefit and risks of moving from a five percent diesel AFCl reduction to the 10 percent reduction. (BP1)

Response: The LCFS standards are based on Governor Schwarzenegger's Executive Order S-01-07, which requires the ARB to establish a plan that reduces carbon intensity of transportation fuels by at least 10 percent by 2020. Lowering the reduction target to five percent would not satisfy the Executive Order and would not provide the necessary GHG emission reductions required by AB 32.

Nevertheless, an estimate of the costs to achieve a five-percent CI reduction and an additional five-percent CI reduction can be inferred by examining the spreadsheets in Appendix G, where the compliance scenarios have year-to-year analyses. A five-percent CI reduction occurs in about 2017 for both gasoline and diesel. A cursory look reveals that there are more cost savings in the latter years than in the earlier years,

due to alternative fuels being less expensive than petroleum-based fuels over this time period, as crude prices are higher and the tax credits remain in place for the biofuels.

I-75. Comment: In response to peer review comments on its economic analysis of the Scoping Plan, CARB explored uncertainty in its estimates by simply *assuming* that costs and savings from the Scoping Plan might differ by particular arbitrary percentages from its primary projections. CARB did nothing to assess how likely such deviations would be, and whether deviations could be even greater than CARB assumed. Therefore, CARB's analysis did nothing to inform policymakers about the true economic risks associated with the particular regulations that it has proposed. Its analysis would be akin to evaluating the value of a corporate bond by *assuming* a particular likelihood of default, rather than by actually evaluating the likelihood of such a default based on the economic condition of the specific company in question. (WSPA1)

Comment: In assessing uncertainty, it is important that CARB evaluate the extent to which costs may differ from its primary projection, and the likelihood of such scenarios. This requires considering the underlying determinants of the cost of the LCFS (e.g., the cost of conventional and low-carbon fuels) and the uncertainty surrounding those determinants. CARB should present the findings from numerous scenarios that appropriately reflect the degree of uncertainty in these key determinants of the cost of the LCFS. (WSPA1)

Response: As previously stated, we used key assumptions in our economic analysis regarding crude prices, biofuel production costs, and tax credits. Furthermore, we conducted sensitivity analyses to account for some degree of uncertainty. To estimate the likelihood of occurrence of any specific deviation or combination of deviations from the initial assumptions introduces a significant amount of speculation and is not practical.

The regulation requires ARB to conduct reviews of the LCFS by January 1, 2012, and January 1, 2015. These reviews will include assessing the cost and availability of alternative fuels. Should the LCFS be determined to be costly to California's economy due to unrealized assumptions or prevailing economic conditions, staff may return to the Board to revise the regulation.

I-76. Comment: LCFS places a rigid requirement on the transportation fuel market that could prove to be extremely costly under certain future scenarios if low-cost low-carbon fuels do not emerge in sufficient supply. Thus, a critical issue that CARB will need to address is whether to adopt particular cost-containment mechanisms and, if so, what kind of mechanisms it should adopt. (WSPA1)

Response: The "cost-containment mechanism" for the LCFS is similar to that of previously adopted ARB regulations: periodic review of the regulation with subsequent modifications, as deemed appropriate and necessary. The LCFS requires formal program reviews in 2011 and 2014, although we may conduct reviews at any time.

Cost-related issues that may surface will be addressed, and, if necessary, staff will recommend regulatory modifications to the Board.

Availability of Fuels

I-77. Comment: Concerned about CARB's intent to proceed to a rulemaking hearing on the Low Carbon Fuel Standard without an adequate economic analysis that answers the question of whether sufficient low carbon fuels will be available. The economic analysis did not include a supply and demand analysis. (AB32IMPG1)

Response: If California receives its historical share of the nation's gasoline market (11.3 percent), the federal RFS2 program will introduce more than three billion gallons of ethanol into the State's fuel mix. The illustrative compliance scenarios in the ISOR indicate that the LCFS should not require additional volumes of ethanol, but that the ethanol will have lower CI values. The LCFS complements the federal program and the successful implementation of the federal program will benefit California.

As stated previously, the LCFS standards are back-loaded, meaning that more reductions are required in the last five years than the first five years. The reason for selecting a back-loaded approach vs. a linear approach was to provide more time for the development of advanced fuels that are lower in carbon content. We believe that there will be sufficient volumes of alternative fuels during the 2010 – 2020 timeframe; however, should that not be the case, staff may recommend modifications of the regulation to the Board.

I-78. Comment: Before proceeding to a hearing on the rule, staff [must] demonstrate the availability and cost-effectiveness of sufficient lower carbon fuels to meet standard through 2020 using existing technologies, based upon publicly available information, and identify the degree to which achieving the standard will require development and commercialization of materials and technologies that are not now commercially available. (AB32IMPG1, CMTA)

Comment: The staff has not addressed whether the LCFS program, as currently crafted, will ensure adequate, reliable and affordable transportation fuel supplies and sufficient infrastructure. (WSPA1)

Comment: Staff's documents do not include a demonstration of the availability and cost-effectiveness of sufficient lower carbon fuels (including production scale and distribution infrastructure) to meet the carbon intensity standards through 2020 using existing technologies. (WSPA1)

Response: We concur with published studies that show considerable success has been achieved in reducing the estimated production costs of cellulosic ethanol. We conducted the economic assessment based on available public data. The references that we utilized to estimate the production costs of alternative fuels are presented in Table VIII-8 of ISOR and are listed in the References section at the end of the chapter.

The standards of the LCFS are back-loaded, and the volumes of cellulosic ethanol and advanced biofuels are modest during the early years, although non-liquid low-carbon fuels, such as electricity, hydrogen, and natural gas, are available today. Pilot-scale plants using waste products as feedstock produce about three million gallons per year of cellulosic ethanol. Furthermore, nearly 300 million gallons per year of advanced biodiesel is being produced worldwide. The technology exists to produce cellulosic ethanol, biodiesel, and advanced diesel; however, the challenge is to make these biofuels cost-competitive with petroleum-based fuels.

NREL, the U.S EPA, and others project that the cost of producing advanced biofuels, including cellulosic ethanol, will decline as technological advances are made and commercial-scale plants are built and operating. We concur with this assessment. Because the LCFS is back-loaded, giving time for these advancements, we assert that to conduct an economic analysis using today's technology is inappropriate.

While we cannot ensure "adequate, reliable and affordable transportation fuel supplies and sufficient infrastructure," we have no reason to believe that the necessary fuel supplies and infrastructure will not be in place to meet the requirements of the LCFS.

Price at the Pump

I-79. Comment: Even if compliance with the proposed LCFS were feasible, the costs likely would cause fuel producers to shift sales to other markets. This would do nothing to address California or global GHG issues, but is likely to cause a significant increase in fuel costs in California. (CNAES)

Comment: We're out there building and fuel cost is very important for our members doing business in California. (CBPA)

Comment: We are concerned about CARB's intent to proceed to a rulemaking hearing on the LCFS without an adequate economic analysis that answers the question of what it will cost drivers at the pump. (AB32IMPG1)

Comment: We're not at all convinced that the program will deliver \$11 billion in savings. All that matters is what the consumer thinks and they want it to be affordable. (WSPA3)

Comment: We also want to know how much it's going to be at the pump, to the end users. (OT-10/WD)

Comment: It will impose higher fuel costs we can't afford. (CBCOC2)

Comment: While LCFS places compliance obligations on upstream entities (i. e., producers and importers of transportation fuels) the increased costs of the fuels required under the LCFS will be borne by consumers. The fact that CARB

does not consider the entities that actually have to purchase the fuel to be affected by this proposal is troubling. (ATA)

Comment: What will these fuels cost? (LBA1, LBA2)

Response: Our economic analysis estimated overall savings of \$0 to \$11 billion during the 10-year compliance period. As stated in previous responses, we based our economic analysis on several key assumptions—assumptions that were collected from several sources, including the California Energy Commission and the NREL, among others.

The cost savings may result in either no impact at the pump (all profits stay with the investors) or lower prices at the pump (some profit passed on to consumer). Should the savings be entirely passed on to consumers, it would represent less than three percent of the total cost of a typical gallon of transportation fuel (\$0 - \$0.08/gal) at the pump. In the early years of compliance, when GHG emissions reductions are more modest, consumers may see a small cost at the pump (less than a penny a gallon) just to get the small volumes of slightly better fuels to California.

We understand that the economic analyses of the LCFS is greatly affected by future oil prices and the actual production costs and timing of lower CI alternative fuels. Economic factors, such as tight supplies of lower-CI fuels or a lengthy economic downturn keeping crude demand down, could result in overall net costs, not savings, of the LCFS.

While disruptions in supply can create temporary price hikes for transportation fuels, these disruptions should be minimized. The transportation fuel industry in the State should consider potential supply disruptions of liquid biofuels when designing and building the necessary infrastructure to transport and store these fuels.

I-80. Comment: Another thing that we've looked at over time is it appears to us as though every policy requiring corn ethanol seems to increase the amount of oil we use and the profit of the oil companies. It's being promoted as a debate between the two and it seems to be a partnership from our perspective. That is costing the people of California additional monies for food, for gasoline and we seem to be using up a lot of water, whether these should be taken into consideration or not, we're not sure, but we'll look upon the expertise of the chair and this committee to possibly look a little further before we go forward. (OT-78/CAP1)

Response: The LCFS will increase the total volume of finished transportation fuel because the energy content of ethanol is less than petroleum-based gasoline; however, the total volume of petroleum-derived fuel will be reduced. The LCFS will provide a market for lower-carbon intensity (CI) fuels, such as cellulosic ethanol and sugarcane ethanol, while discouraging the use of ethanol with higher CIs, such as corn ethanol.

As the oil companies provide transportation fuels for consumers, they are investing in ethanol plants and ethanol technologies so that they can continue to provide transportation fuels. Therefore, in some cases there are partnerships between the oil companies and the producers of alternative transportation fuels.

As part of the environmental impact analysis, we addressed the water required in the production of alternative biofuels, such as cellulosic ethanol. (See Chapter F-Environmental Impacts in this FSOR for more discuss on water).

I-81. Comment: In regards to the economic analysis, further exploration of costs to end users should be explored. There is a lack of analysis of the capital costs associated with new fuels in regards to vehicles and infrastructure, and limited analysis related to the costs of ownership, such as maintenance costs, safety enhancements, and potential fuel economy impacts. Furthermore, an overall cost comparison should be completed between a situation in which a LCFS is implemented and a situation in which there is no change in the current fuel standard. (OCTA)

Response: We considered the potential costs of the LCFS to end users, and estimated that there would be a potential savings of \$0 - \$11 billion over a 10-year period. (See previous responses.) We considered the cost of infrastructure in its economic analysis. We did not consider the vehicle costs in the analysis because the LCFS does not mandate deployment of specialized vehicles—such as plug-in hybrids, battery-electric vehicles, and flexible-fueled vehicles. The number of these vehicles on the road will depend on two factors: a more stringent mandate by the Board, and a public acceptance of these vehicles. The eight illustrative compliance scenarios merely used a variety of vehicle-deployment possibilities.

We included maintenance costs in the production cost of biofuels and addressed the fuel economy impacts in the compliance scenarios (e.g., included additional volumes of ethanol because of its lower energy content). Finally, the economic analysis conducted for the compliance scenarios compared the results to a base case where there was no LCFS regulation.

I-82. Comment: I encourage your consideration of the supply vs. demand impact on the cost of diesel fuel. (EUCA)

Comment: The LCFS economic review completed by CARB leaves many unanswered questions. For example, the absence of a rigorous “supply demand” analysis inhibits CARB from considering the programs impact on reliable and affordable fuel supplies in California’s future. (TESORO1)

Response: We understand that if the demand for lower-CI diesel or ethanol blends exceeds the supply of such fuels, the cost of those fuels will rise. We believe that there will be sufficient supplies of fuels that are an alternative to petroleum-based fuels, such as biodiesel, renewable diesel, lower-CI ethanol, CNG, and electricity. The gasoline and diesel CI standards are back-loaded to allow sufficient time for the construction and

operation of production facilities and necessary infrastructure. Table B-16 in Appendix B (Volume II, ISOR), illustrates that there is currently 1.2 billion gallons of annual alternative diesel capacity in the United States. Furthermore, the federal RFS2 requires one billion gallons of biomass-based diesel in the nation's transportation fuel mix by 2012. If California receives its proportional share of national diesel volumes, and the existing capacity is fully realized, then the early-year (2011-2014) requirements of the LCFS should be satisfied. Similarly, if California receives its historical share of the nation's gasoline market (11.3 percent), the federal RFS2 program will introduce more than three billion gallons of ethanol into the State's fuel mix. The LCFS will not require additional volumes of ethanol, but require the ethanol to have lower CI values.

Finally, as mentioned previously, the regulation requires ARB to conduct reviews of the LCFS in 2011 and 2014. These reviews will include assessing the cost and availability of alternative fuels.

I-83. Comment: The fuel reformulation really makes us nervous as business owners. It doesn't give us the ability to price for new business because we don't know what the additive is that's going into the fuel, we don't know what the end product will be at the price of the pump. (WD)

Response: The proposed regulatory action does not establish any motor-vehicle fuel specifications because the LCFS contains no requirements that dictate the exact composition of compliant transportation fuels (see response to Comment I-51). Regarding possible engine performance issues, refer to the responses in Chapter J (Compliance Scenarios/Technology Assessment). Finally, the price at the pump was discussed in the response to Comment I-79.

I-84. Comment: LCFS and AB 32 are likely to create a severe bureaucracy that will drive prices higher in the transportation sector first, and then for all other sectors as a result. The producers and fuel dispensing businesses are likely to pass on substantial portions of the additional costs to the final consumers thereby having a huge negative economic impact. (CSBR3)

Response: We have estimated that annual reporting and recordkeeping costs will be about \$170,000 per regulated party—less than \$5 million total. Given that the volumes of transportation fuels in the State are nearly 20 billion gallons, even if all of these costs were passed on, the impact would be 1/40th of one cent per gallon. Furthermore, we estimate enforcement costs for ARB to be about \$500,000/year. We consider these costs necessary and minimal.

I-85. Comment: What are the economic effects of plugging in a vehicle into the electric grid? What are the economic effects of using more natural gas for vehicles? (PE1)

Response: Because an electric motor is about three times more efficient than an internal-combustion engine, electricity is one of the least expensive alternative transportation fuels. (See Table VIII-8 of Volume I of the ISOR.)

One of the five illustrative gasoline scenarios had nearly 1.8 million electric vehicles on the road by 2020. We estimated that the total amount of electricity that these vehicles would use would be 4.6 million megawatt-hours, which is 1.4 percent of the current total grid demand. Furthermore, we assume that these vehicles would be recharged during off-peak hours, typically overnight, thereby minimizing their impact on California's electrical grid.

Regarding the use of natural gas, Diesel Scenario #3 had the greatest volumes for CNG use in heavy-duty vehicles, and that amounted to only three percent of the total fuel requirements. Even considering the lower energy content of CNG relative to diesel fuel, the lower cost of natural gas more than compensates, making it an attractive alternative fuel. (See Table VIII-8 of Volume I of the ISOR.)

I-86. Comment: Further analysis by ARB should include impact of a consumption mandate on domestic fuel prices in times of supply shortage due to weather or pest-related crop failures, and the welfare impact if energy prices rise as a result (CERA2)

Comment: Staff does not consider future availability of alternative fuels or any major fluctuations or disruptions in the demand-supply equation and the resulting prices. (CSBR4)

Response: Unlike the federal RFS2, the LCFS does not mandate volumes of consumption of alternative fuels; rather, it requires the average carbon intensity of the fuels in the marketplace to meet specific standards. If the supply of lower-CI alternative fuels is affected by weather or pest-related crop failures, or other reasons, resulting in a significant increase in the State's transportation fuel prices, staff can return to the Board with proposed revisions to the regulation.

As stated previously, the regulation requires ARB to conduct reviews of the LCFS in 2011 and 2014. These reviews will include assessing the cost and availability of alternative fuels.

Small Business

I-87. Comment: The economic analysis offers no analysis on the impact on small business. (AB32IMPG1)

Comment: The State Hispanic Chamber has long been concerned about the cost impacts of AB 32 implementation, especially on our Hispanic-owned businesses and small businesses throughout California. Once again, we're being told that the costs to business will be minimal, if anything at all. Our members

and their employees are worried about losing their businesses, jobs and benefits completely. It seems to me this very important, very human element has been completely lost as you've rushed to adopt the rule that you haven't fully evaluated. And that could impose unsupportable financial burdens on hundreds of thousands of small businesses and families. (CHCOC2, CHCOC3)

Comment: I'm here today as a small business owner. I've made several trips from Southern California to address this Board about the cost of AB 32 implementation and how they will affect small businesses like mine. In any event I've been and remain extremely troubled by the seeming insensitivity to the importance of costs with respect to AB 32 programs like this one. The last thing I and my customers need is a program that will probably make our energy costs go up and might even force people to eventually buy a different kind of car sooner than planned. (CHCC1)

Comment: AB 32 Scoping Plan acknowledged that higher energy costs associated with carbon reductions would disproportionately impact low income communities. If the low-carbon fuel standards mean even a small increase in gas prices, public transportation fees, or higher costs for food and other things that are fuel dependent, it's going to hurt our communities even more. (SFVMAPA1, SFVMAPA2)

Comment: We've all seen what happens when fuel costs go up - and unfortunately high fuel prices hurt small and minority-owned businesses and low-income community hardest because we spend more of our budget on energy. (HCCCCC)

Comment: In the short run there will be required costs that will come down, not only to the consumers, all of us in this room, but also to the small businesses. (CHCC2)

Comment: Staff asserts that the impact on small business will be non-existent since the fuel producers are all large. But the vast majority of fuel dispensers are small businesses. Staff estimates that the cost of installing E85 dispensing infrastructure per existing service station is approximately \$172,000. Staff fails to put this into perspective for small businesses which are currently struggling in this economic downturn and can obtain little or no financing in current credit markets. The economic impact this will have on small businesses has been completely omitted and ignored. (CSBR2, CSBR3)

Comment: The analysis fails to show how small businesses will recoup the required cost of investments in equipment, "especially when CARB's entire economic analysis seems flawed, based on unreasonable assumptions, or inadequate." (CSBR2, CSBR3)

Comment: The analysis does not account for increased costs to small business through fuel prices or equipment investments, or increased costs due to limited supplies of fuel and electricity. The analysis fails to provide methods for minimizing impacts to small business. The LCFS regulation process should be delayed until CARB can set the right example for how all the AB 32 regulations will result in benefits to small business - using sound science and economic analysis. (CSBR1)

Comment: Staff does nothing to measure the impact on small business by simply dismissing the impact with the assumption that small business will recoup the investment and financing costs of the required additional equipment for implementation under LCFS through their future sale of alternative fuels to consumers. Staff does not account for the secondary effects on all small businesses - even those that are not in the business of providing transportation fuels - since every business - regardless of the sector (food, construction, etc.) will be impacted due to the change in transportation modes and costs. (CSBR2, CSBR3)

Comment: Before moving forward with the LCFS, the small business community would like to make sure that CARB ensures that the benefits of economic growth that were promised in the AB 32 legislation are real before approving massive new costs and regulations. (CHCOC1)

Response: The Staff Report addresses the potential impact of the LCFS on small businesses on page VIII-1. The proposed regulatory action would not affect small businesses because: (1) most, if not all, regulated parties are expected to be relatively large businesses, and (2) small businesses (generally the fueling station owners and operators) would presumably invest in equipment that dispenses LCFS-compliant fuel with the expectation that the costs of such an investment would be recouped through sales of such fuels. In regards to fuel prices for consumers and small businesses, the cost savings expected from the LCFS (\$0.02 to \$0.08/gge for the entire California gasoline market, and \$0.03 to \$0.04/DGE for the entire California diesel market) may result in either no impact at the pump (all profits stay with the investors) or lower prices at the pump (some profit passed on to consumer). In the early years of compliance, when GHG emissions reductions are more modest, consumers may see a small cost at the pump (less than a penny a gallon) just to get the small volumes of slightly better fuels to California.

As to the LCFS forcing consumers to eventually buy a different kind of car sooner than planned, the LCFS regulation does not mandate specific volumes of specialized cars and we do not expect the consumer or small businesses to be forced to replace their current vehicles in order for the LCFS to be successful. However, as alternative fuels become more cost-competitive with traditional fuel, specialized vehicles will become a more attractive option to consumers.

I-88. Comment: We also recommend that CARB revisit the economic analysis to appropriately characterize the economic impact of the proposed LCFS on the trucking industry. (ATA)

Response: Businesses for which transportation fuels are a significant expense (such as truckers) should not be impacted by the LCFS as overall transportation-fuel costs are estimated to decline or be unaffected for the consumer.

Job Leakage/ Competitiveness

I-89. Comment: We are also disappointed that you seem so willing to invest billions of our money in a program that cannot possibly slow down global warming unless the rest of the world comes along with us. (CBCOC1, CBCOC2)

Comment: The rest of the world isn't coming with us, neither is the rest of the country. So we'll be spending billions on nothing more than a grand gesture. (CBCOC1)

Comment: This rule should be well-researched, and adopted in the context of the policy actions of other states and the federal government. We can't afford to spend billions of dollars on merely setting an example. (HCCCCC)

Comment: From a business perspective, the higher fuel cost facility associated with the LCFS will be another expense piled on top of higher taxes, fees and environmental regulations that have made us all increasingly uncompetitive with other states and countries. (CBPA)

Comment: California businesses and industries rely on a reliable and affordable supply of high quality diesel fuel to farm, build, and move people and goods. Our members' businesses are not generally in a position to pass along costs of doing business, and many of them are subject to competition from non-California businesses. They already pay the highest energy and fuel costs in the nation. (AB32IMPG2)

Comment: We have a lot of customers that are strictly warehousing in California with us. We think this could cause some leakage where they would seek other companies and other carriers out of the State of California where they can get lower fuel prices in Nevada and Arizona. (WD)

Comment: We are extremely worried that California is doing this alone. Without comparable rules in other states and at the federal level, California will be at an even greater competitive disadvantage than it already is. So we'll lose more business and jobs to other states, who'll bring their pollution across our borders anyway. That's a losing situation all around. (SJCHCC2)

Comment: We're also worried that we're doing this alone. What concerns us is that we might really put ourselves at a competitive disadvantage. So I want to caution you to really evaluate the concerns of the economy and our small businesses. (SJCHCC1)

Comment: This rule has real potential to create a serious economic and environmental imbalance. We're concerned that California is moving faster and farther than other states, the federal government and other countries. Our Chamber works hard to facilitate mutually beneficial business relationships and opportunities on both sides of the border. This productive balance could be severely disrupted by a California-only low carbon fuel standard. What good will it do to put our local businesses at a competitive disadvantage with those neighbors? (SDCHCC)

Comment: CARB is adding major regulatory burdens under AB 32 to the long list of challenges for businesses in California, a move that will surely limit our economic growth success. How can our small business remain competitive regionally if California fails to coordinate with other states as proposed by the Western Climate Initiative? (CSBR1)

Comment: It is unclear what the outcomes are likely to be of other states in the US and other countries either delaying or completely withdrawing from the implementation of lower emission standards similar to LCFS in their respective jurisdictions. The adverse economic impact on Californians through higher costs, displacement of jobs, population out migration etc. have not been discussed or accounted for in the Staff study. Staff takes it for granted that all other states and countries will adopt similar standards. The resulting disparity in fuel production, distribution and consumption prices and its impact on people, productivity, taxes, businesses, and intra state trade are unknown and not discussed or analyzed on the Staff study. It appears that other US states and other countries are still debating similar standards, while California wants to go ahead and implement LCFS anyways even though the others are not anywhere close to adopting similar standards. (CSBR2, CSBR3)

Comment: Staff claims that LCFS will not adversely impact the competitiveness of California businesses, and that LCFS will not result in any leakage of business to other states. But as long as other states do not implement a similar standard, California businesses will automatically be rendered less competitive. This has not been accounted for in the economic analysis. (CSBR2, CSBR3, CSBR4)

Comment: While Staff is quick in pointing out the new jobs that will likely be created due to the new bio refineries expected to be built in the state, they do not discuss the potential job losses due to lower consumption of traditional fuels, the various costs of regulation, and the adverse economic impact on businesses and consumers. (CSBR2, CSBR3)

Comment: Most of the regulatory work will not be completed until the end of 2009. If CARB moves ahead without the legally required documentation, in an effort to spur other states to opt in, the economic harm caused will do just the opposite. While adopting a skeleton rule may provide a political benefit for attempts to leverage other states to adopt the LCFS and send a message to the U.S. Congress about California's program, it places the California's goods movement sector (a significant state employer) in great economic harm and subjects this sector (and California consumers who purchase goods delivered to market by this sector) to price volatility and provides no GHG emission reduction. (IWLA)

Comment: It also seems that California is the only state that is pursuing such an aggressive and ambitious new fuel policy. But it's not fair and it's not smart to rush into this without knowing what it's going to cost and how it might impact fuel supplies. (CBCOC3)

Comment: I think I disagree with the report that it is not to a disadvantage for businesses. It will be a disadvantage. Maybe in the long run it may not be, but in a short run it definitely will be. (CHCC2)

Comment: We know that when big business has to make huge investments, and incur enormous costs for new green policies, those costs are going to find their way down to their customers, small businesses like ours and on to customers, California's families. But sometimes you can't pass those costs along and stay competitive. This is especially true when the rules only apply to California businesses, but not to companies based in other states or other countries. It becomes difficult, if not impossible, to compete with companies that offer the same product or service, but do not have to play by the same rules that we have to play by in our state. (NFIB)

Comment: Before moving forward with the LCFS, the small business community would like to make sure that CARB ensures that the regulation will protect competitive equality for California's businesses. (CHCOC1)

Response: The LCFS regulation will not adversely affect the competitiveness of California businesses and is not expected to result in job leakage. An important goal of the LCFS is to establish a durable fuel carbon regulatory template that is capable of being exported to other jurisdictions. The successful implementation of an effective framework in one jurisdiction should hasten the adoption of that framework elsewhere. Indeed, other jurisdictions are following California's lead and developing measures similar to the LCFS. For example, a regional consortium of eleven Northeastern and Mid-Atlantic States has committed to developing an LCFS that is generally based on the same premise as the California LCFS. In fact, in July 2009, the consortium published the results of its own assessment of an LCFS for the Northeastern and Mid-Atlantic

states.¹⁰ Oregon is pursuing the development of an LCFS. Oregon's Environmental Quality Commission must adopt an LCFS by January 1, 2011. The Oregon LCFS must include a full life-cycle analysis of the fuel and requires a 10 percent reduction from 2010 to 2020 in the carbon intensity of a unit of fuel energy. At the federal level, the RFS2 requires that 36 billion gallons of biofuels be sold annually by 2022, of which 21 billion gallons must be "advanced" lower carbon biofuels and the other 15 billion gallons can be corn ethanol. The RFS2 will bring three billion gallons of ethanol to the State, with or without the LCFS, but the LCFS will draw more of the advanced ethanol to California in the next 10 years.

We have estimated that the LCFS should have no impact or result in slight savings to the price at the pump, so transportation-related businesses in California will not be harmed. To the extent that California can produce more of its own transportation fuel, lower the amount of money spent on imported oil or petroleum products, and lower dependence on out-of-state biofuels, business competitiveness should be improved overall in the State.

Impact on Typical Business

I-90. Comment: An additional concern I have about the proposed regulation is an assertion that there will be no significant impact on businesses for complying with this proposed regulation. This assertion is made even though an acknowledgement was made that additional annual cost for a typical business would be slightly less than \$1 million. This amount may not seem like a significant figure to some, but I assure you that this is a significant substantial impact to businesses who are already struggling to stay afloat in the current economy. (CSC)

Response: Regulated parties under the LCFS will be large businesses: refineries, biorefineries, ethanol importers, and oil importers. The annual ongoing costs for these businesses include the recordkeeping and reporting costs, and maintenance cost. We estimate that it would take one person-year (PY) at \$170,000 per PY, for a business to comply with the recordkeeping and reporting requirements. For maintenance costs, we used a typical industry estimate of two percent of annual capital recovery cost. We applied these factors to the highest infrastructure cost (a \$350 million biorefinery), resulting in annual capital cost recovery of \$52 million and, therefore, an annual maintenance cost of approximately \$1 million. As for smaller businesses, the LCFS does not mandate the installation of E85, CNG, or hydrogen dispensers at any specific facility. Facility owners who choose to invest in these fuels will do so with the expectation of recovering the cost and increasing profits.

¹⁰ Introducing a Low Carbon Fuel Standard in the Northeast is available at: <http://www.nescaum.org/documents/lcfs-report-final.pdf>

Current Economic Climate

I-91. Comment: The economics are clearly important, especially in the context of the current recession. Recent volatility in fuel prices has demonstrated how even small fluctuations can impose a great hardship on businesses and consumers alike. (CBPA)

Comment: At this time we're suffering from the recession. We can't afford higher fuel costs. We can't afford to replace our personal and business vehicles with the ones your plan is counting on to get the emissions reductions, even if they do turn out to be available soon, which is doubtful. (CMCC, SVHCC)

Comment: CARB has ignored the current economic conditions we are all facing in California. Consider all the facts, including the current state of the economy and the global nature of global warming, before imposing yet another financial burden on a state increasingly less able to afford it. (CBCOC1)

Comment: We have asked for the AB 32 process to be slowed down so that the necessary economic analysis could be completed and regulation adopted that wouldn't put a lot of folks out of business and hurt our economy anymore that it has already done. We've been told that is impossible because of statutory deadlines. Consequently, the Black Chamber is sponsoring 5B 295. It doesn't ask to stop AB 32, but to wait until the economy is in better condition to bear the costs of implementation. It's tied to the unemployment rate - which right now is higher than it's been in 25 years or so. (CBCOC1)

Comment: And it's unlikely the LCFS will materially reduce global warming, since California will be the only place in the country or even on the planet to pursue such an aggressive program, during this time of international recession and when California is experiencing an unemployment rate of 11.2 percent, record unemployment rate. (NFIB)

Comment: The agriculture production industry is not in the position to pass along the potential higher diesel costs or any other costs, for that matter, onto consumers. California farmers are already suffering from the cost of the cumulative regulations placed on them and a downward spiral of the economy. California production farmers are either leaving California to farm elsewhere or are closing down their farms completely. (WG)

Comment: While we support the diversification of our fuel technology and supply and driving innovation to reach our AB 32 goals, we must also be sensitive to the current state of the economy. (CCOC)

Comment: If you go ahead with this rule now, without honestly assessing the costs and benefits, you could well be imposing extreme financial burdens on an

already-struggling economy, without making a dent in global warming.
(HCCCCC)

Comment: As a small business person, I've seen my customer base decrease and my costs increase as a result of not only the bad economy, but the State's budget deficit. People who can't afford it are scaling back or canceling their insurance. And those who can are being careful about how much they carry.
(CHCC1)

Comment: One of the anticipated benefits of the program was the expected construction of facilities to produce biofuels and other fuels in the state of California to generate "green" jobs, use local feed stocks and improve fuel reliability/security concerns. Based on the current situation in the state, these anticipated developments are in question and ARB needs to assess whether these benefits will materialize. (WSPA1)

Comment: The San Joaquin Valley is suffering more than the rest of the state in this economic recession. Our members, mostly small and minority-owned businesses, care about the environment. But because they have to stretch everyone single one of their own pennies just to stay alive, they expect the agencies that make rules impacting how they do business and what it costs to be equally careful about the costs. (SJCHCC3)

Response: We are sensitive to the current economic situation of the State, and, as required by AB 32, developed the LCFS in a manner that minimizes costs and maximizes the total benefits to California. The CI standards in the LCFS are back-loaded, meaning more GHG emissions reductions and corresponding compliance costs will occur in the later years of compliance when lower-CI fuel technology has matured and been commercialized. The LCFS compliance schedule allows time for future investments to be made in California-based biofuel technologies and related jobs when the economy has had a chance to improve.

Although there may be a slight cost in the early years of compliance to bring modest volumes of lower-CI fuels to California, we expect that ultimately there will be no impact or a slight savings to the consumer's fuel cost from implementing the LCFS.

Regarding the LCFS forcing consumers to eventually buy a different kind of car sooner than planned, the LCFS regulation does not mandate specific volumes of specialized cars and we do not expect the consumer or small businesses to be forced to replace their current vehicles in order for the LCFS to be successful. However, as alternative fuels become more cost-competitive with traditional fuel, specialized vehicles will become a more attractive option to consumers.

Penalty for Unconventional Petroleum Resources

I-92. Comment: Discrimination among petroleum-based fuels is not necessary to achieve the purposes of the AB 32 program and would in fact be counterproductive. The primary effect would be to discourage imports to California of fuels derived from other unconventional resources in North America, such as oil sands in Canada or oil shale in the Western U.S. This would have an inflationary effect on fuel prices in California, as these cost effective North American fuels would not be available. The adverse economic impacts would affect low income citizens disproportionately, an effect that AB 32 expressly seeks to prevent. The California economy would suffer, but worldwide emissions would not be reduced and in some cases would be increased. This is precisely the situation that AB 32 and AB 1007 seek to avoid, in requiring a regulatory program “that is equitable, seeks to minimize costs and maximize total benefits,” and “minimizes the economic costs to the state” (secs. 38562(b)(1), 43866(b)(2)). It is also apparent that the costs of discrimination against non-conventional fuels would far outweigh the potential benefits, if any. We did not see any discussion of this issue in the economic and environmental analyses accompanying the proposed LCFS. The potential GHG reduction benefits of the discriminatory provisions would be negligible. (CNAES)

Response: The LCFS standards are based on Governor Schwarzenegger’s Executive Order S-01-07, which requires the ARB to develop a low carbon fuel standard that reduces the carbon intensity of transportation fuels by at least 10 percent by 2020. We have identified alternative transportation fuels that would meet these requirements and potentially result in overall savings to Californians. (See previous responses.)

By its nature, the LCFS discourages the use of higher-carbon-intensity fuels, such as petroleum-based fuels from oil sands and oil shale, regardless of price. However, we believe that, with a worldwide economic recovery and a diminishing supply of crude oil, crude prices will rise, making alternative fuels more competitive.

An important goal of the LCFS is to establish a durable fuel carbon regulatory template that is capable of being exported to other jurisdictions. The successful implementation of an effective framework in one jurisdiction should hasten the adoption of that framework elsewhere. Without the wider adoption of fuel carbon-intensity standards, fuel producers are free to ship lower-carbon-intensity fuels to areas with such standards, while shipping higher-carbon-intensity fuels elsewhere. The end result of this fuel “shuffling” process is little or no net change in fuel carbon-intensity on a global scale. With a widespread adoption of an LCFS, significant reductions in fuel carbon intensity will begin to be realized on a global scale. It is ARB’s intent to continue coordinating California’s LCFS program efforts with those of other interested entities, including a regional consortium of eleven Northeastern and Mid-Atlantic States, Oregon, and the European Union.

I-93. Comment: It should be noted that the modeling results are based on the assumption that the mandated sale of low carbon fuels will have no impact on the use of higher carbon fuels in areas not subject to the regulation. This is an unrealistic assumption because, to the extent that an LCFS decreases the demand for higher carbon fuels, the cost of such fuels will tend to decrease in areas not subject to a LCFS regulation. Lower cost will lead to increased consumption, which has been completely ignored in this analysis. Similarly, the analysis ignores the effect on fuel demand of the lower prices for low carbon fuels projected in the ISOR. If low carbon fuels were actually lower in price than conventional fuels, demand would be higher than baseline demand and there would be less of a reduction in GHG emissions. (WSPA1)

Response: We understand the potential for “leakage” and “shuffling” of higher-CI fuels into non-LCFS jurisdictions. (See response above.) As stated previously, we estimated a potential \$0 - \$11 billion savings from the LCFS between 2010 – 2020, based on several key assumptions, including increased crude prices and continued tax incentives. We also stated that these savings may be taken as profit by the fuel manufacturers and not passed on to the consumers. The LCFS may be cost-neutral.

While other transportation measures, such as increased average fuel economy of the vehicle fleet and better land-use planning, will reduce the demand for transportation fuels, the California Energy Commission and the Energy Information Administration see crude prices increasing as overall worldwide demand increases over the next 20 years. Therefore, we do not believe that the LCFS will have a significant impact on overall transportation fuel demand to the extent that fuel prices will be affected.

Macroeconomic Analysis

I-94. Comment: Finally, Staff does nothing in their study to truly measure economic impact using an input output model that can measure the direct, indirect, and induced costs or benefits that account for the multiplier effect on the economy and jobs and take into account regional economic dynamics. They also do not use any economic model such as the EDRAM model used for the scoping plan. With no economic modeling or major sensitivity analyses, the Staff economic analysis is not robust, reliable, or understandable. Their analysis could benefit by incorporating many of the important and critical but omitted economic principles that drive economic impact studies. In this sense the Staff study reads more like an afterthought to support a decision already made, and a strong opinion expressed without much numerical support. (CSBR2, CSBR3)

Response: We considered using an equilibrium model, such as the Environmental-Dynamic Revenue Analysis Mode (E-DRAM), to conduct a macroeconomic analysis of the proposed regulation. A model such as E-DRAM is most useful when it is used to evaluate the economic impacts of a large-scale policy on the State economy. The model can be informative at the sector level with the understanding that some details that may be important in characterizing how producers will respond to a policy change

may not be fully reflected in the model. Because the economic effects of this regulation depend in large part on those responses by the producers, we determined that this type of macroeconomic analysis would not provide useful additional information.

Nevertheless, some general impacts of the LCFS can be assumed:

- Biofuels will displace some percent of petroleum-based transportation fuels.
- The displaced fuels will first be imported blendstocks for transportation fuels, as the State's refineries cannot meet the current demand for these fuels.
- Reducing the volume of transportation fuels that are imported from other states will reduce foreign imports of oil into the U.S.
- State's refineries will continue to operate at capacity during this period. If State demand for fuel declines below this capacity, we assume refineries will export fuels at some loss in value since California RFG3 has a premium value.
- The biorefineries expected to be built in the State will provide needed employment, an increased tax base for the State, and value added to the biomass used as feedstock. These benefits will be more important in rural areas of the State that are short on employment but rich in natural resources.
- Displacing imported transportation fuels with biofuels produced in the State keeps more money in the State.

I-95. Comment: The economic analysis completed by Staff makes no attempt to either discuss or quantify changes to demand, prices, and resulting emission levels of traditional fuels under scenarios of very high crude prices when consumers will change behavior and consumption patterns and hence impacting the level of emissions. (CSBR2, CSBR3)

Response: We did not discuss potential impacts of very high crude prices in the Staff Report. As previously mentioned, we used crude price estimates from CEC's 2007 IEPR: \$66 - \$88/bbl for the time period of 2010 - 2020. Over this modest range, we did not believe that driving behavior would be significantly affected. However, if crude prices were to be considerably higher than these estimates, fuel prices would escalate, people would drive less, and emissions from the transportation sector would decrease. Furthermore, these high fuel prices would make alternative fuels more cost-effective and attractive, increasing their use, resulting in lower GHG emissions, and perhaps reducing the average carbon intensity of the State's transportation fuels to levels below the LCFS standards.

J. COMPLIANCE SCENARIOS/TECHNOLOGY ASSESSMENT

In order to determine the feasibility of the LCFS, the staff prepared several scenarios for achieving both the gasoline and diesel standards. Four of the scenarios pertain to gasoline and fuels that can substitute for gasoline and three pertain to diesel and its substitute fuels. Each scenario described a compliance path involving a different combination of advanced renewable fuels, and advanced electric and hydrogen-powered vehicles. The compliance scenarios demonstrated that compliance is possible, given what is currently known about the future availability of alternative fuels and vehicles. In addition, the compliance scenarios showed that compliance is not contingent upon the availability of only a limited number of alternative fuel-vehicle combinations. Tables ES-10 and ES-11 in the Staff Report present a summary of the contribution of various fuels for each of the scenarios.

This section addresses comments received related to both the availability of the technology needed to comply with the LCFS and the compliance scenarios.

In order to determine the feasibility of the LCFS, the staff prepared several scenarios for achieving both the gasoline and diesel standards. Five of the scenarios pertain to gasoline and fuels that can substitute for gasoline and three pertain to diesel and its substitute fuels. Each scenario describes a compliance path involving a different combination of advanced renewable fuels, and advanced electric and hydrogen-powered vehicles. The compliance scenarios demonstrate that compliance is possible, given what is currently known about the future availability of alternative fuels and vehicles. In addition, the compliance scenarios show that compliance is not contingent upon the availability of only a limited number of alternative fuel-vehicle combinations. Tables ES-10 and ES-11 in the Staff Report present a summary of the contribution of various fuels for each of the scenarios. Appendix E of the Staff Report provides all eight scenarios.

This section addresses comments received related to both the availability of the technology needed to comply and the compliance scenarios.

Compliance Scenarios

J-1. Comment: The LCFS should be met with an emphasis on electric vehicles and electric hybrid vehicles. (AIR)

Response: The LCFS is performance-based, in which fuel producers choose their own mix of pathways to meet the regulation requirements. We anticipate electric vehicles, which provide significant reductions in carbon intensity, will play a role in meeting the requirements.

J-2. Comment: The use of diesel in the light duty fleet will result in significant reductions in both GHG emissions and in the use of petroleum for transportation – two key objectives of the LCFS. The use of diesel in the light duty fleet will also

facilitate future, additional GHG reductions. Early adoption of light duty diesel vehicles will allow for an eventual transition to the use of biodiesel/renewable diesel in these same vehicles, and diesel hybridization using biodiesel/renewable diesel. (BP1)

Response: The LCFS regulation as approved by the Board requires fuel used in light-duty diesel vehicles to meet the diesel standard. The Staff Report provided two analyses of the potential GHG reductions that might be generated if light-duty diesel vehicles instead were allowed to generate credits against the gasoline standard (see Staff Report pp. VI-16 through VI-18). Both analyses looked at one million diesel vehicles displacing one million gasoline vehicles by 2020. The first analysis assumed that the diesel fuel used would meet the 2020 diesel LCFS standard, the second analysis assumed that the diesel fuel would continue to just meet the 2010 diesel LCFS standard over time (if, for example, there were no LCFS diesel standard requiring reductions).

For the first analysis, if the assumption is made that one million light duty vehicles will enter the fleet by 2020, these one million light-duty diesel vehicles running on fuel that complied with the 2020 diesel LCFS carbon intensity standard of 85.24 gCO₂e/MJ would emit 3.9 million metric tons of CO₂ per year. The difference between that and the comparable gasoline-powered vehicle emission level of 4.7 million metric tons would yield the number of credits generated, about 0.8 million metric tons per year.

For the second analysis, one million diesel vehicles running on fuel which met the 2010 diesel baseline fuel carbon standard of 94.71 gCO₂e/MJ would emit higher volumes of CO₂: 4.3 million metric tons per year. The credit earned by these vehicles would be the difference between this 4.3 million metric tons per year, and the corresponding 4.7 million metric tons emission rate for one million gasoline vehicles meeting the 2020 gasoline LCFS standard, or about 0.4 million metric tons per year.

Assuming diesel fuel used in light-duty diesel vehicles was compared to the gasoline standard, achieving even this modest GHG reduction (0.4 to 0.8 million metric tons per year), would require the California light-duty diesel fleet to grow to one million vehicles by 2020. An increase of this magnitude in the California light duty diesel vehicle population appears to be unlikely. There have not been many diesel passenger cars and diesel light-duty trucks certified in California in recent years. More medium-duty diesel truck models have been California-certified. Despite this availability, they continue to comprise under 0.5 percent of the medium-duty vehicle fleet. Additional factors likely to influence the size of the future vehicle fleet are:

- a. The increasing efficiency of gasoline vehicles will continue to close the efficiency gap separating gasoline from diesel vehicles; and
- b. The price of diesel fuel may not drop significantly below the price of gasoline.

Because the estimated GHG reductions would be modest and a significant population increase is not expected, light-duty diesels would not be anticipated to generate large

GHG reductions even if they were credited against the gasoline standard instead of the diesel standard. On the other hand, light and heavy-duty diesel vehicles, including hybrids, can generate credits from the use of lower carbon intensity biodiesel/renewable diesel.

J-3. Comment: Increasing the light duty diesel fleet in conjunction with using renewable diesel (FAHC) would potentially exceed Governor Schwarzenegger's long term goal of reducing GHG emissions by 80 percent by 2050. The commentor provides calculations and discussion based on citing a Carbon Intensity (CI) value of 15 g. CO₂e/MJ for renewable diesel, as provided in Table VI-4 of the Staff Report/Initial Statement of Reasons. (MARZ)

Response: This is correct. However, at this time, there is an inadequate supply of renewable diesel and light duty diesels for this to happen. The LCFS is designed to allow for the development of new low carbon intensity fuels. Only modest reductions are required in the early years and more expedited reductions in the later years. If successful, this will enable the LCFS to be extended into the future and achieve even greater reductions.

J-4. Comment: It is essential that the program contain a realistic compliance schedule that is coupled with commercially feasible, proven, and cost-effective compliance options for obligated parties. (CONOCO) [ASC, 2637]

Response: The Board approved a realistic compliance schedule coupled with realistic compliance options for obligated parties, as well as provided for periodic review of the regulation. Please see ISOR V.D.1., Pages V-5 to V-6 and ISOR VI.B.4., Pages VI-4 to VI-17.

J-5. Comment: Most compliance scenarios string together a series of assumptions and assertions without any apparent technological validity. Staff seems overly optimistic that the "right" fuels and vehicles will be available in the timeframes considered. We recommend ARB clearly outline all of the assumptions and assertions used in their analysis along with an assessment of how the compliance schedule could change if different scenarios are chosen. (WSPA1)

Response: We are confident the technology exists and is progressing so that vehicles and fuels will be available to meet the LCFS compliance schedule. ARB addressed the issue of the production and availability of the fuels that might be used to comply with the LCFS in Volume I, chapter III (Technology Assessment) of the ISOR. As stated in the ISOR, the diversity of promising low-carbon fuel options along with the substantial research and development efforts to bring advanced technologies to the market leads us to conclude that compliance with the LCFS is feasible. See also responses to Comments J-6 and J-26.

The LCFS scenarios are presented in the Staff Report to illustrate several of the many possible scenarios which would meet the requirements of the regulation. The LCFS is performance-based, in which fuel producers choose their own mix of pathways to meet

the regulation requirements. The Board approved a realistic compliance schedule coupled with realistic compliance options for obligated parties, as well as provided for periodic review of the regulation. Please see ISOR V.D.1., Pages V-5 to V-6 and ISOR VI.B.4., Pages VI-4 to VI-17. We do not anticipate that the compliance schedule will change.

Fuel Technologies

J-6. Comment: A LCFS for diesel fuel relies exclusively on fuels (not vehicles) that are currently not commercially viable and must be addressed differently than passenger car fuels. (IWLA)

Response: The LCFS does not rely exclusively on fuels that are currently not commercially viable. ARB addressed the issue of the production and availability of the fuels that might be used to comply with the LCFS in Volume I, chapter III (Technology Assessment) of the ISOR. As stated in the ISOR, the diversity of promising low-carbon fuel options along with the substantial research and development efforts to bring advanced technologies to the market leads us to conclude that compliance with the LCFS is feasible. In addition, the federal Energy and Independence Security Act of 2007 mandates the use of increasing amounts of advanced and cellulosic biofuels beginning in 2009/2010 and continuing on through 2022 and will ensure the availability of advanced fuels through 2022.

The LCFS performance standards start slowly with modest reductions of carbon intensity (CI) in the early years to allow time for the development and production of advanced fuels that are lower in CI than today's fuels. Given the progress in current research and development efforts and the mandates of the federal Renewable Fuel Standard, this approach should work. For example, Volume I, pg III-6 of the ISOR states that as of September 2008 there were 176 commercial biodiesel plants operating in the U.S. according to the National Biodiesel Board with a capacity of over 2.6 billion gallons. Volume II, Appendix B provides additional information.

The LCFS is a performance standard and allows for credits for all low CI fuels, biogas CNG/LNG, hydrogen, and electricity and their penetration into the market as described above.

J-7. Comment: That is why we are so very concerned about the low carbon fuel standard. Without doing the economic, the environmental and the technical analyses, as required by law, CARB staff is asking you to believe that the goals of the LCFS can be achieved at minimal cost, and that by commanding various fuel additives or new fuels to be introduced, that they'll actually be available, practical and affordable. (NFIB)

Response: Thorough technical, economic, and environmental analyses for the LCFS were conducted and are documented in the ISOR. ARB addressed the issue of the production and availability of the fuels that might be used to comply with the LCFS in

Volume I, chapter III (Technology Assessment) of the ISOR. As stated in the ISOR, the diversity of promising low-carbon fuel options along with the substantial research and development efforts to bring advanced technologies to the market leads us to conclude that compliance with the LCFS is feasible. See also response to Comment J-6. See also section F (Environmental Impacts) and section I (Economics).

J-8. Comment: The pace of what we need to do in order to make this program successful is that in 5 year's time, there needs to be about 4 to 7 cellulosic plants being built per year until 2020. (NRDC4)

Response: The ARB cannot substantiate the claim that in 5 year's time, there needs to be about 4 to 7 cellulosic plants being built per year until 2020. The Staff Report analysis does include a potential for 18 new cellulosic ethanol facilities of about 50 million gallons per year in California (see Staff Report p. VII-9), and acknowledges cellulose as a mid-term technology projected by 2015 (see Staff Report p. III-14). So it is possible that multiple new facilities to supply California could be under construction, in-state or out-of-state, in any given year. And we note that biofuel volumes under the LCFS compliance scenarios are comparable to biofuel volumes under the federal renewable fuels standard program, so we would expect most of those facilities would be built anyway under the federal program. However, there are many factors – economic, technical, legal, and practical – that impact when, where, how big, and even whether a biofuel facility is built. Under the low carbon fuel standard, there are multiple technologies and multiple fuels besides cellulosic biofuels that could be used for compliance, so we cannot say that 4 to 7 cellulosic plants per year would need to be built beginning in 2015.

J-9. Comment: We do not know if the fuels, additives or technologies will be available, or even invented or perfected, to meet the requirements of this standard. (SDCHCC)

Response: The ARB believes that the fuels, additives, and technology required for the LCFS will be available. As stated in the ISOR, the diversity of promising low-carbon fuel options along with the substantial research and development efforts to bring advanced technologies to the market leads us to conclude that compliance with the LCFS is feasible. See also response to Comment J-6.

J-10. Comment: Now you are considering the first major rule under AB 32. And it looks like you're still not doing the analysis necessary to truly figure out what the LCFS will cost, whether the technology is or will be available, and what the impacts will be on the environment and public health. (SVHCC)

Comment: The technology for producing ethanol from cellulosic feedstocks has not been proven on a commercial scale and no commercial plants have been built. (TESORO1)

Comment: For renewable diesel blends, recipes are not a problem because renewable diesel is acceptable at all blend levels. However, even though the feasible blend ratios are expected to be smaller than for biodiesel after staff resolves the inconsistencies we have found in the pathways and adjusts the preliminary ILUC impact to 40 gmCO₂e/MJ, the global volume requirements may be hard to supply if other jurisdictions adopt similar low carbon fuel requirements. (A2O4NES)

Comment: Establish if there is ample supply. (HTC)

Comment: The phase-in schedule needs to take into account the need for technology to develop. Section 2 of the draft outline indicates that CARB is considering a linear phase-in schedule for the new standards. Rather than a linear phase-in schedule, CARB should promulgate a phase-in schedule that requires smaller reductions in the early years of the program and larger reductions in later years. Compliance with the low carbon fuel standards will require the development and commercialization of technology that is not available today. Fuel technologies such as cellulosic ethanol and Biomass-To-Liquid (BTL) fuel are currently still in the demonstration phases and will take time to build-up their production base to adequately meet market requirements. When considering the time needed to phase-in the requirements, CARB should consider not only the LCFS, but also the renewable fuel mandate requirements under the recently enacted Energy Independence and Security Act (EISA). The renewable fuel requirements under EISA apply to parties that will be obligated parties under the California LCFS but also other parties. Thus, refineries and importers outside of California will be competing for the same volumes of second generation biofuels that California refiners and importers are competing for to satisfy the LCFS obligation. The phase-in schedule should recognize this and provide time for the technology to develop and commercialize. (SHELL)

Comment: Second generation biofuels, and in particular cellulosic ethanol, are likely to be key technology to achieve the emission reductions required by a low carbon fuels standard. However, while cellulosic ethanol holds great promise, it is important to recognize that it is not yet commercially available and that production capability build-up may not develop on a timeline sufficient to meet the 2020 LCFS goals. (SHELL)

Comment: Staff's documents do not include a demonstration of the availability and cost-effectiveness of sufficient lower carbon fuels (including production scale and distribution infrastructure) to meet the carbon intensity standards through 2020 using existing technologies. One of the anticipated benefits of the program was the expected construction of facilities to produce biofuels and other fuels in the state of California to generate "green" jobs, use local feed stocks and improve fuel reliability/security concerns. Also, staff should have identified the degree to which meeting the LCFS will depend upon the development and commercialization of technologies and materials that are not now commercially

available, to give some sense to policymakers of plausible response times and key uncertainties. (WSPA1)

Response: There is evidence that the fuels and technology required for the LCFS will be available. ARB addressed the issue of the production and availability of the fuels that might be used to comply with the LCFS in Volume I, chapter III (Technology Assessment) of the ISOR. As stated in the ISOR, the diversity of promising low-carbon fuel options along with the substantial research and development efforts to bring advanced technologies to the market leads us to conclude that compliance with the LCFS is feasible. See also responses to Comments J-6 and J-8.

J-11. Comment: CHOREN requests that CARB amend the Technology Assessment sections of the Initial Statement of Reasons ("ISOR") to include CHOREN's Fischer-Tropsch biomass-to-liquids ("BTL") technology. We suggest that item 2 on Page III-16 be supplemented to include the commercialization status for CHOREN's BTL synthetic fuel. The expanded discussion of renewable diesel commercialization Volume II of the ISOR also fails to mention CHOREN. (CHOREN)

Response: The ISOR is not intended to be a comprehensive list of all fuel production technologies. It is intended only to discuss the staff's proposal, the basis for the staff's proposal, and some of the most promising technologies that the staff anticipates will likely be used to meet the requirements of the regulation. The information referenced can be used in applying for approval of new pathways under Methods 2A/2B.

J-12. Comment: CHOREN strongly supports ARB's ongoing efforts to establish these needed additional pathways. The expanded discussion of renewable diesel commercialization Volume II of the ISOR also fails to mention CHOREN. We request that Table B-12 on B-37 be supplemented to include the following information:
NAME: CHOREN
LOCATION: Freiberg, Germany
CAPACITY: 3.9 million gallons per year
START-UP: Fourth quarter, 2009
STATUS: Commercial, Demonstrator is in commissioning stage
(79) (CHOREN)

Response: Same as response to Comment J-11.

J-13. Comment: Ensure the LCFS ushers in a new generation of ultra-low carbon fuels. The proposed regulations should be amended to ensure "ultra-low carbon fuels" will be part of the compliance mix in the early years. (NRDC3)

Response: The LCFS is designed to provide a durable framework that uses market mechanisms to spur the steady introduction of lower carbon fuels. The LCFS does not specify which combination of fuels the regulated parties must provide to comply with the

standards. This allows flexibility and a lower cost of compliance. “Ultra-low carbon fuels” may be some of the low carbon fuels that may help to meet the standards of the LCFS.

Fuel Availability

J-14. Comment: In June and December 2006, ATA submitted numerous comments on ARB’s original and revised draft biodiesel policy. These comments discussed the trucking industry’s concerns with biodiesel use, including the cost of biodiesel, the need to ensure biodiesel quality, the impact of biodiesel use on nitrogen oxide emissions, and the operational challenges for on-road use of biodiesel in blends exceeding five percent. These comments are still relevant in the context of the revised draft biodiesel policy. Although we do not repeat the concerns raised in our June and December 2006 comments, we do incorporate them by reference hereto. (ATA)

Response: The 2006 comments noted by the commenter pre-date the LCFS development and approval by the Board by more than three years. While those 2006 comments may have been relevant to the original draft and revised draft biodiesel policy, the policy itself was never formally adopted by the Board and is no longer applicable in any case. This is because the policy was drafted to address the fact that, in 2006, there were no State standards governing the sale of biodiesel, which was beginning to enter the market in substantial quantities at that time. Since then, the Division of Measurement Standards promulgated regulations governing biodiesel quality based on ASTM specifications (ISOR at II-11 and II-12), with the understanding that ARB may promulgate motor vehicle fuel specifications for biodiesel at a later date. Therefore, the 2006 comments no longer apply to any ARB policy, draft or otherwise. Indeed, when the Board approved the LCFS regulation in April 2009, it did not incorporate either the original draft or the revised draft biodiesel policy referred to by the commenter.

Further, the commenter fails to identify the particular comments in its 2006 submittals that still apply specifically to the LCFS regulation that was considered and approved by the Board in April 2009. It would be difficult and impractical for staff to determine which of the 2006 comments still apply to the Board’s adoption of the LCFS regulation without additional specificity from the commenter.

Based on all the reasons discussed above, the comments contained in the 2006 submittals are applicable to a biodiesel policy that is irrelevant to the LCFS regulation. Therefore, the 2006 comments are non-responsive to and outside the scope of the April 2009 hearing notice, despite the commenter’s incorporation by reference of those comments. As such, no agency response to the June 2006 comments are needed or appropriate.

It should be noted that, with regard to the cost of biodiesel, need to ensure biodiesel quality, the impact of biodiesel on NOx emissions, the operational impacts of blends

greater than B5, and other considerations raised by the commenter, these are all factors that will be considered when the Board promulgates a motor vehicle specification for biodiesel. As the commenter acknowledges in its April 22, 2009 letter, ARB staff are in the process of developing a proposal to establish motor vehicle specifications for biodiesel and renewable diesel, which is tentatively scheduled to be considered by the Board in 2010 (ISOR at II-12; formerly scheduled for late 2009, now tentatively scheduled for mid- to late-2010).

J-15. Comment: The LCFS compliance schedule likely will require increasing percentages of biodiesel blends beginning in 2011. While renewable diesel that meets ASTM D-975 is expected to perform comparably to today's ULSD fuel, first generation biodiesel (i.e., biodiesel that complies with ASTM 6751 and is used for blending into ULSD) will present operational challenges for the trucking industry as the blend rate increases. The LCFS envisions the use of B20 and contains no limits on biodiesel concentrations. (ATA)

Response: We disagree for several reasons. First, as noted previously, the Board found in Resolution 09-31 that the LCFS regulation does not, by itself, establish a motor vehicle fuel specification for diesel, gasoline, or any other fuel or blendstock. Instead, the regulation is performance-based, and fuel providers have a variety of compliance options. These options include, but are not limited to, providing fuels with lower carbon intensity than the specified standard, purchasing credits from other regulated parties, and retiring banked credits generated in a previous compliance year. Therefore, the LCFS does not require increasing percentages of biodiesel blends beginning in 2011.

Second, as noted in the response to Comment J-1, ARB staff plans to propose for the Board's consideration in 2010 fuel specifications for biodiesel and renewable diesel used in motor vehicles. As part of that rulemaking, the Board will presumably consider any operational challenges the trucking industry or other stakeholders may raise as an issue with increasing biodiesel blend rates.

Finally, as a performance standard, the LCFS does not, by itself, require regulated parties to produce B20 or any other biodiesel blend, notwithstanding the compliance scenarios (hypothetical scenarios for lowering the carbon intensity of the entire motor vehicle fuel pool in California) discussed in the Staff Report (ISOR at VI-1 through 22). Biodiesel blends are currently capped by the Division of Measurement Standards (DMS) at B5 (ISOR at II-12); even though ASTM has adopted specifications for B6 through B20, DMS has not yet promulgated regulations to adopt the ASTM specifications for B6 through B20. If and when ARB promulgates its own specifications for biodiesel blends, such specifications will presumably establish a scientifically-defensible limit on biodiesel based on the best available data at the time of the Board's approval of the specifications.

J-16. Comment: While many in state leadership positions have promoted the use of biodiesel, a flaw in the state's legal and regulatory structure is prohibiting its storage in underground storage tanks (UST), above B5 levels. This has taken a

significant portion of biodiesel out of the stream of commerce. As new fuel types and fuels line up to enter into the fuel mix, others such problems are likely, if not predictably to occur. (CIOMA1)

Comment: With regard to the UST storage issue of biodiesel above B5, the State Water Board will not allow storage of biodiesel above five percent blend in underground storage tanks (USTs). There is a disconnect between the certification of a fuel for its readiness in the stream of commerce and the time that it gets introduced by a marketer or by a supplier. It's a simple check list. It just requires looking at several issues. Have appropriate certifications been finalized with independent parties, so that the underground storage tanks, the nozzles, the trucks are all certified to use it? Have appropriate public noticing issues been resolved, such as in the Division of Measurement Standards? (CIOMA2)

Response: The biodiesel storage problem referred to by the commenters is beyond the control of the Board. As the commenter correctly points out, it results from requirements under State Water Resources Control Board (SWRCB) regulations. The SWRCB regulations prohibit fuel from being stored in underground storage tanks (USTs) unless those USTs have been certified by an nationally-recognized, independent testing organization as being compatible with such fuel (23 CCR §2631 et seq). At this time, the only nationally-recognized certification for USTs is conducted by Underwriters Laboratory (UL), which is currently backlogged and has not yet certified UST systems for biodiesel blends above B5 (5 percent biodiesel).

The SWRCB recently addressed this issue by promulgating emergency regulations to allow variances, for up to three years, that would permit the storage of biodiesel blends up to B20 (20 percent biodiesel, 80 percent CARB diesel) in UST. (23 CCR §2631.2, effective 6/1/09-12/1/09). The SWRCB found that this period of time should be sufficient to allow UL to complete its certification of UST systems for use with biodiesel blends higher than B5 and up to B20.

J-17. Comment: Are insurance companies willing to ensure [sic] the liability of handling these fuels (biodiesel blends above B5)? And will the fuel harm any vehicle or engine that it's intended to be put into? (CIOMA2, SJCHCC2)

Response: Whether insurance companies are willing to insure the liability of handling biodiesel blends is an issue that is entirely up to the insurance industry and fuel suppliers, marketers, and distributors to negotiate. This issue is beyond the scope of the 45-day notice for public comments; therefore, no response is necessary.

As noted previously, the issue of whether biodiesel blends greater than B5 may have impacts on engine or vehicle performance will be considered during the rulemaking to establish motor-vehicle fuel specifications for biodiesel and renewable diesel. That rulemaking is tentatively scheduled in 2010. Because the LCFS neither requires nor establishes any specifications for biodiesel blends, the issue of engine and vehicle

performance while using biodiesel is best addressed specifically during the biodiesel rulemaking in 2010.

J-18. Comment: CARB staff is currently undertaking studies looking at the effect of low blends on the fuel efficiency of the biodiesel versus a pure fuel at common blend levels. This study effort is not completed, but results should be available prior to the implementation of the rule in 2010. We would like to suggest that you review this data when it is available from CARB studies or use other data of NREL or US EPA as a guide and adjust the lifecycle emissions of at least biodiesel to account for its actual fuel efficiency at the most common blend levels (2 percent, 5 percent, 10 percent, and 20 percent). (CO2STAR)

Response: The regulation already addresses this concern in several ways. First, the Board recognized in Resolution 09-31 that ongoing studies and developments in engine technologies may necessitate in the future changes in the energy efficiency ratios (EERs) that are codified in Table 5, section 95485(a) of the LCFS regulation. Therefore, the Board delegated authority to the Executive Officer in Resolution 09-31 to conduct and complete rulemakings to amend any portion of Table 5, including but not limited to, adding a new EER or revising an existing EER. Similarly, the Board delegated authority to the Executive Officer to conduct rulemakings to, among other things, revise any existing fuel pathway or carbon intensity value (except values based on land use or other indirect effects that are specified in the Carbon Intensity Lookup Tables as adopted in this rulemaking). Finally, the LCFS was modified, pursuant to the Board's directive, to include formal implementation reviews in 2011 and 2014 in section 95488. The scope of the review is to include, among other things, a review of advances in full, fuel-lifecycle assessments. Based on all these reasons, we believe that the LCFS regulation, as modified, and the implementation activities to be conducted pursuant to the Board's directives are already designed to cover and incorporate up-to-date fuel efficiency data for diesel engines using biodiesel at the most common blend levels suggested by the commenter.

J-19. Comment: We support a public process for developing a new diesel fuel recipe in 2010. As end users, the Health and Safety Code protects us from the introduction of new diesel fuel recipes which are not vetted. This is because of the catastrophic engine failures and price spikes occurring in 1993 due to the lack of in-use testing. While the fuel recipe in 1993 was disclosed, the lack of compatibility between legacy engines and the new fuel caused serious financial harm to diesel users statewide. In light of existing state law, we are seeking the following milestones to be met prior to a new recipe or renewable standard required for 2010. Getting it right is simple; the state has to follow the law and:

- a. provide the industry with the new recipe or pathway,
- b. conduct testing of no less than 30 diesel vehicles ranging from 1998 to 2009 in partnership with diesel users,
- c. disclose the use of any renewable fuel additive or process that lowers carbon intensity in diesel fuel and disclose the source of the products origin, and

- d. determine the incremental cost per gallon of each recipe at the rack each year until 2020.

If CARB moves ahead without the above legal milestones completed, we collectively are seeking State indemnification for end users. (FORMLETTER4)

Comment: If we use this new fuel, will we be indemnified for its use, or if there are any problems with storm water or Proposition 65 issues? (WSA, WSGM)

Comment: We would like to see the Board complete its work on the diesel portion of the regulation before adopting it, so that the performance, supply and price impacts can be realistically assessed. (WG)

Response: ARB staff plans to conduct a rulemaking to propose motor-vehicle fuel specifications for biodiesel and renewable diesel. We plan to propose such a regulation for the Board's consideration in 2010. As part of that rulemaking, the issues raised by the commenter will be considered, including but not limited to, what the "recipe" for a compliant biodiesel/renewable blend might look like; what engine testing is appropriate; compatibility of biodiesel/renewable diesel blends with new and legacy engines; and the supply and incremental cost impacts of compliant fuel blends. As with other ARB regulations, the 2010 biodiesel/renewable diesel rulemaking is subject to the public process prescribed under the Administrative Procedure Act (Government Code section 11340 et seq.). Because the LCFS regulation does not, by itself, establish a motor vehicle fuel specification, the issues raised by the commenter are best addressed as part of that 2010 biodiesel/renewable diesel rulemaking rather than in the LCFS rulemaking.

With regard to the commenters' requests for indemnification to address costs and other impacts due to possible engine performance issues, we note that there's no need to address this request at this time. This is because the engine performance issues raised by the commenter as a pre-condition to seeking indemnification are to be considered as part of the 2010 rulemaking, as discussed above. However, we also should note that, even if the Board were to consider such a request for indemnification at this time, the request cannot be granted. This is because, under State law, the Board has no authority to grant the requested indemnification without express authorization by the Legislature. The commenter did not identify any cases or statutes that would authorize the Board to grant such indemnification, and the Board is unaware of any authority that would likewise grant it such authority.

With regard to storm water or Proposition 65 issues, compliance with the LCFS does not relieve a regulated party or end user from their obligations to comply with other applicable regulations, such as storm water or Prop. 65 requirements. While it is not absolutely necessary, the LCFS regulation contains a savings clause to make this clear to the regulated community.

J-20. Comment: We do not want a return to what happened in 1993 when the fuel (diesel) was reformulated. The State was very gracious in helping us replace our fuel pumps. But we lost man-hours, had service failures to our customers, and downtime of our equipment. So whatever you do, bring me something that has been tested and that we can use and be comfortable with. (WSA)

Comment: We want you to do a multimedia review of the fuel that you choose to pass and make us feel comfortable about what we're putting in our trucks. We also ask you to do the proper testing and wait until around December before you adopt the fuel. And if you do adopt it, we would like to see some kind of periodic testing or public review of the regulation every six months until 2020 to ensure that the vehicles and equipment are not impacted by this change of fuel. Lastly, at the January workshop I offered our fleet as a test fleet, and that offer still stands. (WSA)

Response: The need for conducting a multimedia evaluation was addressed in the response to Comments E-21 through E-40. With regard to the LCFS' adoption date, the Board approved for adoption the regulation, with modifications, at the April 2009 hearing. The Board did not believe an extension of the adoption date was necessary.

With regard to periodic testing or public reviews, the Board agrees that periodic monitoring of the LCFS implementation is necessary. As noted in the response to Comment C-272, the LCFS contains provisions for two mandatory reviews by 2012 and 2015, and the Board directed the Executive Officer to periodically monitor the LCFS implementation and return to the Board with amendments as needed. The Board considered the commenter's suggestion and determined that the suggested 6-month periodic reviews are unnecessary given the two mandatory reviews and its monitoring direction to the Executive Officer.

J-21. Comment: We are unsure of how CARB will ensure that biodiesel use does not increase NOx emissions; however, we note that the use of fuel additives to address this issue will further increase the cost of biodiesel and will require significant testing to ensure that it will not adversely impact engine durability or the long term efficacy of emissions control equipment. (ATA)

Response: ARB staff plans to conduct a rulemaking to propose motor-vehicle fuel specifications for biodiesel and renewable diesel in 2010. As part of that rulemaking, staff will evaluate, among other things, whether NOx increases due to the use of higher levels of biodiesel can be mitigated through the use of additives or other mitigation strategies and, if so, the incremental costs associated with such mitigation. The staff will also assess the need for engine testing to address engine performance issues such as those raised by the commenter. Because the LCFS does not establish a new fuel specification for biodiesel and does not affect existing biodiesel standards by the Division Measurement Standards, there is no need to conduct at this time the suggested engine testing and additive cost analysis suggested by the commenter.

J-22. Comment: The LCFS discussion on biodiesel NOx emissions is particularly troubling. Rather than accounting for the fact that the use of biodiesel will increase NOx emissions, the report ignores the prevailing body of scientific evidence on the subject because it undermines the plan for biodiesel substitution. NOx is of particular interest because biodiesel has been reported to increase NOx emissions. ARB staff has assumed that there will be no increase in the emissions of NOx. This is because staff is currently conducting an extensive test program for biodiesel and renewable diesel and will follow that effort with a rulemaking to establish specifications to ensure there is no increase in NOx. (ATA)

Response: We agree that NOx is an important consideration when establishing a motor-vehicle fuel specification for biodiesel. As we discussed in the response to Comment J-14 and as the commenter itself points out, ARB staff is currently conducting an extensive testing program for biodiesel and renewable diesel. This test program is designed to provide information in support of a NOx-mitigated fuel specification to be considered by the Board in 2010. Therefore, the Staff Report's treatment of NOx from the use of biodiesel under the LCFS program is appropriate because the implementation of a biodiesel fuel specification by ARB will be based on a NOx-mitigated fuel specification that will be proposed to the Board in 2010.

J-23. Comment: Scenarios 1 and 2 assume 15.8 million gge of hydrogen in 2020; Scenario 3 assumes 24.8 million gge, and Scenario 4 assumes 49.6 million gge. What is the basis for these assumptions in terms of demand and the required infrastructure? What is the basis for the technological feasibility of these implementation rates? What is the cost-effectiveness of this approach to carbon control? (WSPA)

Response: Demand was based on the average expected fuel use for fuel cell vehicles. The number of fueling stations for the alternative fuels (e.g., hydrogen) and their cost were included in the cost effectiveness analysis that was conducted for each compliance scenario. This information was presented in Chapter VIII of the Staff Report.

J-24. Comment: There is no clear pathway to ethanol of any kind as a significant source of low carbon fuel. Therefore, the LCFS should not place an emphasis on how placing E85 filling stations throughout the state *[sic]*. This part of the LCFS is guiding investment into potentially wasteful activity. Please drop any reference to E85 infrastructure until there is a clear low carbon way to produce the fuel. Wait a few years to see exactly where the ethanol industry is headed. (AIR)

Response: The Renewable Fuel Standard program requires increasing the use of renewable fuels, such as ethanol, every year through 2022. Therefore, we believe it is important to support the development of E85 infrastructure while the LCFS regulation drives the production of lower carbon fuels. The State has funded numerous E85 stations through the AB 1811 (Alternative Fuel Incentive Program) and will continue to

do so under AB 118 (Alternative and Renewable Fuel and Vehicle Technology Program).

Vehicle Technologies

J-25. Comment: The use of CAFE to encourage the production of FFVs and its impacts on fuel use should be ended, and all US automakers should be required to produce mostly FFVs. There is little or no difference between legacy vehicles and FFVs as shown in the parts manual. Or, if the differences are significant, corrective costs are less than more elegant cup holders, usually less than \$100. (BCC2)

Response: The CAFE Standards are set by the federal government, and therefore, ARB cannot amend them. Regarding FFVs, the federal RFS2 program will bring more than 3 billion gallons of ethanol to California, with or without the LCFS, and drive the need for E85 and FFVs (see response to Comment B-13).

Vehicle Availability

J-26. Comment: The LCFS scenario vehicle values are unrealistic and based on the ZEV regulation, which has a tendency to change. How can ARB staff be certain the vehicle volumes will materialize? How can Scenarios 3 and 4 even remotely be considered technologically or economically feasible? (WSPA1)

Response: The LCFS scenarios are presented as possible combinations for compliance and are not required scenarios. The LCFS regulation does not regulate Zero Emission Vehicle (ZEV) sales volumes. Scenarios presented were to demonstrate that emissions reductions can be met with various volumes of fuels and associated vehicle populations. The values presented in the scenarios are not annual sales volumes but vehicle populations comprising Plug-In Hybrid Electric Vehicles (PHEV), Hydrogen Electric Vehicles (HEV), Battery Electric Vehicles (BEV), and Fuel Cell Vehicles (FCV). Compliance can be achieved through multiple combinations of fuels produced which reduce the overall carbon intensity by ten percent including a scenario that does not include ZEVs. ARB staff is confident due to its inherent knowledge and regulatory view that OEMs will meet the 560,000 vehicle scenario projections. To ensure a path is set that will assure the state achieves the 2050 GHG emission reduction goals while ensuring criteria pollutant emissions reductions, the ZEV regulation is being revised and staff will review and adjust emissions and vehicle volumes. The revisions to the ZEV regulation will assist achievement of the goals of the LCFS regulation in addition to ensuring achievement of the 2050 GHG emissions reduction goals.

J-27. Comment: CARB needs to account for the incremental cost of vehicle technologies assumed in some of the scenarios that go beyond what is required by the ZEV mandate (and even the ZEV mandate numbers are tenuous given the number of times the regulation has been modified over the years). This doesn't

appear to have been accounted for, and for some of the technologies that ARB is looking at (fuel cells, plug-ins, etc.), it is hard to argue that they would arrive solely as a result of AB1493. (WSPA1)

Response: The LCFS regulation is not a vehicle mandate and does not require a specific volume of vehicles. Therefore, the cost associated with regulation compliance pertains to the fuel cost. The cost analysis for the base case ZEV vehicles are captured in the ZEV regulation which pertains directly to these vehicles. Vehicles beyond the ZEV base case are not required and are options based on manufacturer's compliance plan. In March of 2008, the Board directed staff to redesign the ZEV regulation for 2015 and beyond. This new regulation will review the economic impacts and discuss the fueling infrastructure that is needed for ZEVs. Modifications to the ZEV regulation help ensure the state is on track to achieve its long term goals by gauging the progress and forecasting future changes that may be necessary.

J-28. Comment: Diesel Scenario 7 assumes introduction of plug-in hybrids to the heavy-duty fleet. What is the technological and economic feasibility of this approach? Again, the LCFS compliance pathway is dependent on technology innovation so it is essential ARB conduct progress and forecast reviews every three years. (WSPA)

Response: Scenario 7 is not a requirement but a potential pathway to compliance. The LCFS regulation seeks to reduce carbon emissions from fuels and does not require the regulated parties to produce any specific vehicle types. As the regulation moves forward, periodic reviews will be done to ensure that the emissions reduction goals are being achieved.

J-29. Comment: The ZEV regulations were originally adopted in 1990 and required BEV sales beginning with the 1998 model year. The regulations have since been changed numerous times in order to delay production requirements for BEVs due their high cost and limited performance relative to conventional vehicles. The latest assessments of battery and fuel cell technology indicate that these problems with cost and performance will continue into the future and suggest that additional changes to the ZEV regulations to delay production requirements will continue to occur. (WSPA)

Response: While delays from the original ZEV production requirements have occurred, progress in technology development indicates steady progress towards commercialization and thereby towards meeting production requirements. The ZEV regulation has continued to foster clean conventional vehicles and facilitate adoption into the California fleet. As the ZEV regulation moves forward it will continue its focus on zero emissions vehicles their associated technologies and that the state is on track to achieve its long term emission reduction goals. Compliance with the LCFS can be achieved with multiple combinations of fuels and pathways: the ZEV fuels are an opt-in option to allow an ultra low carbon fuel to assist with compliance. The LCFS regulation

seeks to reduce carbon emissions from fuels and does not require the regulated parties to produce any specific vehicle types.

Fuel and Vehicle/Technology Availability

J-30. Comment: Will the fuels and vehicles required have been invented, perfected, and tested within the timeframe required? Will existing vehicles run on the new fuels without damaging their engines? Or will businesses and families have to invest in new cars and trucks? (LBA1, LBA2)

Comment: Our conclusion is the LCFS rulemaking looks very similar to the ZEV mandate regulation when it was first introduced, with unrealistic expectations about technology development leading to a need for reviews and amendments. We are concerned ARB has taken the same approach with the LCFS, and this is likely to lead to problems with the transportation fuels system. (WSPA1)

Comment: There is also general agreement the LCFS program is relying heavily on fuels and vehicles that have either not been produced yet, or are not currently commercially viable. This is similar to the ZEV program that has seen a multitude of changes over the past 20 years, following early optimism for innovative technology advancements that did not materialize in the marketplace as anticipated. The ZEV program has had to be altered every few years. (WSPA1)

Comment: The staff has not addressed whether the LCFS program, as currently crafted, will ensure adequate, reliable and affordable transportation fuel supplies and sufficient infrastructure. This is of great concern in a state that admittedly has placed itself previously in the position of being a fuel island with problems being created by the state's desire to lead the world – but with higher costs borne by consumers. (WSPA1)

Comment: It doesn't appear that your staff has fully explored the costs of meeting the standard, or even knows if all the fuels, technologies and infrastructure necessary will be even available, much less affordable. (HCCCCC)

Comment: In supporting its draft regulation for the California low carbon fuel program, ARB lays out compliance scenarios that contemplate the availability of over 2.24 billion gallons of advanced renewable fuels and over 560,000 advanced vehicles (battery, plug-in hybrid, and fuels cell) in California in 2020. These expectations are unrealistic. ARB's projection that 560,000 advanced vehicles will be available for sale in California in 2020 appears unsupported and, in fact, contrary to the Energy Information Administration's (EIA) forecast. National growth trends do not appear to support 560,000 advanced vehicles in California by 2020. (WSPA1)

Comment: In addition, we are concerned about the feasibility of the LCFS. All of the potential compliance scenarios proposed rely on advanced biofuels that are not commercially available, advanced vehicles and significant transportation fuel (including biofuel) infrastructure investment requirements above the truck rack, at the truck rack and at retail outlets. (VALERO)

Comment: We are writing to express our serious concern about the California Air Resources Board's intent to proceed to a rulemaking hearing on the Low Carbon Fuel Standard (LCFS) without an adequate economic analysis that answers the question of whether sufficient low carbon fuels will be available, what it will cost drivers at the pump, and without first fully understanding the environmental impacts of this rule. (AB32IMPG)

Comment: You can't have one without the other. That's why I've come here from Oakland today to ask you to take more time to fully evaluate the Low carbon Fuel Standard. The purpose of the standard is to reduce carbon emissions from transportation fuels, which contribute to global warming. But it appears that the true costs of this policy have not been thoroughly analyzed, the necessary fuels developed and/or available, and the full environmental and public health impact of some fuels not evaluated as required by law. (CBCOC1)

Comment: We're very concerned that the adoption of the LCFS today is premature and could result in significant fuel supply cost and quality problems that will harm California's economy and jeopardize success of the program. We believe the LCFS has not been adequately evaluated in terms of availability of low carbon fuels, the impact on energy prices, and environmental impacts. Those concerns have been reinforced by findings of a recent review of CARB staff analysis by Sierra Research, which concluded that the LCFS would increase fuel costs in California by \$3.7 billion a year by 2020 and increase smog-forming emissions by five tons a day. Sierra characterize the staff's projections as overly optimistic about the number of alternative fuel vehicles that will be on the road and the cost of producing and distributing biofuels such as corn ethanol. (CMTA)

Comment: It's not at all certain the necessary technologies and fuels that we need to implement this standard have been perfected, produced, or are going to be available in sufficient quantities to meet the standard. (CBPA)

Comment: Demonstrate the availability and cost effectiveness of sufficient lower carbon fuels to meet the standard through 2020 using existing technologies based on publicly available information; and identify the degree to which the standard will require development and commercialization of materials and technologies that are not yet commercially available. (CMTA)

Comment: On the Federal level we have seen the Renewable Fuels Standard impacted by the lack of commercial installations for cellulosic and other second generation biofuel production. For the LCFS, the adoption of specific indirect

land use for advanced biodiesel implies that advanced biodiesel technologies are closer to commercial feasibility than most industry experts currently anticipate. We are concerned that the proposed regulations, which include setting an ILUC benchmark and substantial Volume assumptions for advanced biodiesel, may put the regulations far ahead of the commercial realities. (COMF1)

Response: Regarding biofuel availability and technological feasibility and economic evaluation, see response to Comments J-6 and J-8. Regarding electric vehicle availability, see response to Comment J-26. Regarding FFV availability, see response to Comment B-13. Regarding plug-in hybrid availability, an independent panel established by ARB in 2006 found that plug-in hybrid electric vehicles can achieve mass commercialization in the 2015+ timeframe. Recent research has shown that there is an ample supply of idle electrical generation and transmission capacity to accommodate a significant increase in electric vehicle use. Any new fuel for use in existing vehicles has to be registered with the U.S. EPA. Before a new fuel can be registered, the U.S. EPA must make a finding that no damage will occur to the engine or its air pollution control equipment. While the LCFS is not designed to require replacement of existing vehicles, the LCFS is designed to provide credits to new technology vehicles that use low carbon intensity fuels. These include plug-in hybrids, hydrogen fuel cell vehicles, battery electric vehicles, and compressed natural gas fueled vehicles.

Permitting of New Biorefineries

J-31. Comment: The staff report states that 25 new biorefineries could be built in California to produce the lower carbon-intensity fuels. Having direct experience with air permitting requirements, social justice issues and having worked with entities that have been unable to permit new biorefineries; we remain extremely skeptical of this staff determination and its projected ability to help meet LCFS standards. (CAC1)

Response: Over the past several years, several corn to ethanol plants have been built as well as a number of biodiesel plants in California. It is possible to site, construct, and operate biorefineries in California. The number 25 is based on an estimate of feedstock availability in California made by the University of California. Some of these plants will be constructed in response to the U.S. EPA renewable fuel standard not only in response to the LCFS. Staff, as directed in Resolution 09-31 approving the LCFS, is developing a guidance document for local districts to use in permitting new biorefineries.

Promotion of New Plant or Process

J-32. Comment: We have developed a process that converts post-recycle municipal solid wastes and other waste feedstocks to 100 percent cellulosic ethanol. The utilization of waste streams for biofuels is a low carbon fuel pathway with no land use impact and should be an important part of any low carbon fuel standard. Later this year Fulcrum will break ground on Project Sierra, which is our first commercial scale facility, that will produce ten and a half million gallons of

cellulosic ethanol annually from waste material. The project located in Storey County, Nevada, is an important step forward in demonstrating the near-term viability of a low carbon fuel pathway that turns waste material into ethanol. (FULCRUM)

Response: The ARB agrees that cellulosic ethanol from waste material is a low carbon fuel that can be part of the LCFS.

More Analysis Needed/Technology

J-33. Comment: The availability of new technologies can be predicted for a limited number of years into the future with a minimum of speculation. The program reviews should recognize this and focus on aligning the standards of the program with the availability of the technologies required to comply over a subsequent 3-4 year period. Over such a short timeframe, projections can be based on then-currently available technologies and concrete construction plans.

Unfortunately, such an analysis was not performed for the initial years of the LCFS as part of this rulemaking. Instead, the analysis in the Staff Report appears to be just as speculative in the early years of the LCFS as it is in the later years. As a result, the feasibility of the program in the first few years of compliance has not been established. (CHEVRON)

Comment: I can't just say, "Me too." Now you're considering the first major rule under AB 32. And it looks like you're still not doing the analysis necessary to truly figure out what the LCFS will cost, whether the technology is or will be available, and what the impacts will be on the environment and public health. (CMCC)

Comment: The LCFS is one of the largest components of AB 32 and likely to be one of the most expensive. Yet your staff has failed to complete critical economic, technical and environmental studies necessary to successfully develop and implement the rule. Still, they tell us it won't cost much, and seem to think that by decreasing the development of new fuels and vehicles will make it happen despite daunting scientific, technological and cost hurdles. (CON10U)

Response: After considering all testimony, the Board accepted that an adequate technological analysis for the LCFS was conducted and is documented in the ISOR. ARB addressed the issue of the production and availability of the fuels and technologies that might be used to comply with the LCFS in Volume I, Chapter III (Technology Assessment) of the ISOR. The technology assessment includes a discussion of current technologies, mid-term technologies projected by 2015, and long term technologies projected after 2020. Some of the fuels and technologies in the LCFS are already in use, are practical, and are available. These are adequate for the early years of the LCFS.

See also response to Comment J-30 above.

Timing Differences Among Alternatives

J-34. Comment: A more explicit recognition of the timing differences among the alternatives would be useful in understanding the practical application of a LCFS and establishing realistic expectations for implementation and achievement of its targets. For example, electric, hydrogen and compressed natural gas may be used to meet the requirements of LCFS but their expected time to market is much longer than grain and cellulosic ethanol, and will require significant investment in new infrastructure (with related costs and full impacts yet to be determined). (DUPONT1)

Response: ARB addressed the issue of the production and availability of the fuels and technologies that might be used to comply with the LCFS in Volume I, chapter III (Technology Assessment) of the ISOR. The technology assessment includes a discussion of current technologies, mid-term technologies projected by 2015, and long term technologies projected after 2020.

The LCFS is a performance standard and allows for credits for low CI fuels, including biogas CNG/LNG, hydrogen, and electricity and their penetration into the market. The LCFS per year standards are “back-loaded”; that is, there are more reductions required in the last five years, than the first five years. This schedule allows for the development of advanced fuels that are lower in carbon than today’s fuels and the penetration of plug-in hybrid electric vehicles, battery electric vehicles, fuel cell vehicles, and flexible fuel vehicles.

See also response to Comment J-30 above.

Carbon Capture and Geologic Sequestration

J-35. Comment: In such instances, fuel processes that use CCS technologies cannot be considered a low-carbon fuel under any circumstances when the carbon can eventually escape. Even very low leakage rates through cracks or fissures in the ground and oil wells could reverse any purported climate benefits achieved by CO₂ burial. By factoring in theoretical and unproven CCS reductions in a given fuel’s GWI value the ARB would not reflect actual emissions reductions, and would in effect allow-in dirtier crudes that could in turn lead to increased toxic and criteria pollutant emissions. To address this potential backsliding dynamic, we recommend that 1) ARB thoroughly analyze the full lifecycle for each individual grade of feedstock including all dirtier crudes, incorporating all processing stages such as extraction and refining; 2) The LCFS be an entity-specific regulation so that dirtier fuels cannot hide behind averaged default values; and 3) the LCFS should not give any credit for use of CCS technologies.

The explicit reference to CCS in the proposed regulatory language would raise a very real and substantial threat to all communities surrounding sites of sequestration and storage, and encourage investments needed elsewhere in questionable technologies. A large leak of CO₂ could kill vegetation, animals, and humans over a fairly large area. Fuel providers could target EJ communities in California that have large oil-well fields, such as in Bakersfield, Wilmington, and other areas vulnerable to natural disasters like earthquakes. Thus, the potential siting of CCS projects in traditionally overburdened communities could also violate AB32's statutory mandate to not disproportionately impact traditionally overburdened communities. (CERA1)

Comment: Carbon Capture & Storage Technologies Do Not Represent “Real” and “Permanent” Emissions Reductions and May Disproportionately Impact Low-Income or Traditionally Overburdened Communities. We oppose all CCS technologies as wasted investments that physically threaten surrounding communities. The proposed LCFS may incentivize (i.e. “pick a winner”) the CCS technology that has not been proven to even work. The ISOR states:

“Large stationary sources of carbon dioxide, such as refineries and power plants are most viable candidates for CCS. Gasoline and diesel produced from such refineries could receive lower lifecycle carbon intensity values under the LCFS.”

“Staff is proposing that any regulated party, using a high carbon-intensity crude oil (> 15 g CO₂e/megajoule) brought into California that is not already part of the California baseline crude mix, would have to report and use the actual carbon intensity for that crude oil unless the party demonstrates that it has reduced the crude oil’s carbon intensity below 15 g CO₂e/megajoule using carbon-capture-and sequestration (CCS) or other method.”

We greatly oppose the inclusion of any CCS technologies in the LCFS, whether related to the transportation sector or not. Oil produced using CCS technologies will not have a lower net GWI than conventional crude oil when nobody has yet to prove that the carbon can remain permanently sequestered, and projects could impose other environmental harms including threatening groundwater quality and supply. (CERA1)

Response: Carbon Capture and Sequestration, which is the process of capturing CO₂, then compressing, transporting, and injecting it into a suitable underground formation for long term sequestration, is most viable at large stationary sources such as utilities, cement plants, and refineries. The LCFS allows consideration of CCS in determining whether a crude oil qualifies as high carbon intensity crude.

Leading scientists with the Intergovernmental Panel on Climate Change (IPCC) have agreed that the risks of geological storage would be comparable to risks of current activities. With measures in place to minimize potential risks, the IPCC estimates that CO₂ could be trapped for millions of years, and formations are likely to retain over 99

percent of the injected CO₂ over 1000 years¹¹. CO₂ is unlikely to escape from a well selected, designed, and managed site.

EPA's Underground Injection Control (UIC) Program in the Office of Water has released a draft regulation for permitting CO₂ injection that is designed to protect groundwater¹². Any CCS site would need to apply for a UIC permit, which includes outlining their site characterization, monitoring, and management plans. As part of the U.S. EPA and other permitting procedures, there would be a public hearing to address any local concerns, including siting. These processes will address the location of specific sites.

J-36. Comment: A number of analysts evaluating greenhouse gases have concluded that asphalt is a "green" product in part because it sequesters a significant portion of the crude oil barrel that would otherwise be burnt as motor vehicle fuel. Asphalt is also a "green" option to displace concrete highways, since concrete emits significant CO₂ as it is manufactured. (PP1)

Response: For the most part, asphalt is made from the heavier portions of crude that often can't be made into transportation fuel. So, saying asphalt sequesters a significant portion of the crude oil barrel that would otherwise be burnt as a motor vehicle fuel is an inaccurate statement. Both asphalt and cement emit significant CO₂ as they are manufactured. It would be inaccurate to call asphalt a "green" option as compared to cement on this basis.

Miscellaneous Comments

J-37. Comment: Our company is leading the way in developing new alternatives to traditional fossil fuel production. In fact, California is a world leader in the development of advanced biofuels. The state is home to major universities, federal laboratories and several companies that are developing advanced biofuels that can replace traditional fossil fuels. At the same time, many of these new technologies in development can be utilized in our existing energy and fuel infrastructure. (BAYBIO, COMF1)

Response: ARB welcomes the participation of companies developing emerging alternative fuel technologies in the LCFS program.

J-38. Comment: Our company recently developed a technology that employs biological and mechanical processes to increase the yield at today's corn plants from an industry average of 2.69 un-denatured gallons per bushel to 3 gallons

¹¹ IPCC, 2005. Bert Metz, Ogunlade Davidson, Heleen de Coninck, Manuela Loos and Leo Meyer (Eds.) Cambridge University Press, UK. pp 431.

¹² U.S. EPA 2008. 40 CFR Parts 144 and 146 [EPA-HQ-OW-2008-0390 FRL-8695-3]. Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO₂) Geologic Sequestration (GS) Wells. 2008. (CERA1, 2834; CERA1, 2833; ES)

per bushel. More ethanol from less corn is consistent with LCFS and ILUC. These regulatory incentives will help the producers adopting our technology find an eager market for their low carbon ethanol in California. (EDENIQ)

Response: ARB supports the development of new technologies that improve fuel production efficiency and ultimately lower the carbon intensity. Method 2A in section 95486 of the regulation provides an opportunity for such emerging technologies to qualify a new sub-pathway with a lower Carbon Intensity (CI) value.

J-39. Comment: The key to a successful transition to a low carbon future will be entrepreneurial innovation. The state should err on the side of encouraging such innovation. The effects of regulation on the energy sector are so fundamental, far-reaching and complex, that prudence and time are needed to achieve the greatest net environmental and social benefits possible. (UCD2)

Comment: The LCFS needs to spurn innovative new fuel sources like algae or bacteria processes which can generate fuel with a smaller carbon footprint. (SIERRA CLUB)

Response: The LCFS is intended to encourage new fuel pathways. Methods 2A and 2B included in section 95486 of the regulation allow technology innovations to be recognized and be assigned appropriate CI values.

J-40. Comment: Over the last 7 years, we have analyzed hundreds of different feedstocks from around the world. Our current favorites are used cooking oil, Jatropha Curcas, which is grown on wasteland and is an inedible product, as is algae. I think these are two areas that should be looked at more closely. The analysis for algae (I'm told by the scientists) is that the theoretical maximum is about 5 kilograms per cubic meter per day. If you run the numbers, and just look at the biomass byproduct that could be used for animal feed, as an example, that would displace over 800 acres of corn and a thousand acres of soybean. (BI)

Comment: Rice growers continue to search for economic uses for rice straw they are no longer burning in the field. Seed and other agricultural biotechnology companies are partnering with research institutions including the University of California to develop energy crops for California conditions that will enhance the economy and the environment. (CACA1)

Comment: CCA does not oppose biofuels production, but would urge future biofuel products to be derived from things currently being unused, such as waste rather than feed crops. (CACA2)

Response: The LCFS is designed to encourage the development and use of low-carbon alternative fuels. For example, feedstocks that can be used to produce renewable fuels include, but are not limited to, cellulosic waste materials from agriculture, sugarcane, forestry wastes, municipal wastes, waste oils, and animal fats.

Methods 2A and 2B included in section 95486 of the regulation allow new fuel pathways to be recognized and be assigned appropriate CI values.

J-41. Comment: We are getting a new high efficiency natural gas power plant to replace our old plant. Plus plug-in hybrids will also help. Battery technology is getting better. These technologies will help reduce our dependence on petroleum fuels. (HAMILTON)

Response: Plug-in hybrids with improved battery technology may be eligible to participate in the LCFS program.

J-42. Comment: Today we have already secured exclusive access to enough MSW feedstock for the annual production of more than 1.3 billion gallons of ethanol. In California, we have plans to develop several projects throughout the state that will utilize post-recycled MSW to produce an aggregate volume of between 100 and 200 million gallons per year. (FULCRUM)

Response: The LCFS is designed to reward fuel pathways such as this by allowing CIs to be assigned through method 2A and 2B.

K. LIFECYCLE ANALYSIS

Comments and responses in this section are related to published fuel pathways and the GREET model. Carbon intensities are calculated under the LCFS on a full lifecycle basis. This means that the carbon intensity value assigned to each fuel reflects the GHG emissions associated with that fuel's production, transport, storage, and use. In addition to these direct GHG emissions, some fuels create emissions due to indirect land use change effects, which are addressed in Section L of this report.

K-1. Comment: The California-modified GREET model proposed pathway uses outdated data regarding ethanol production. For example, the regulation appears to incorporate ethanol energy use data from 2001. Ethanol production facilities have made significant advances in energy usage since 2001. Without accounting for these advances, the regulation significantly overestimates the energy used to produce ethanol. With the dramatic increase in state-of-the-art refinery capacity soon to be on line, average industry energy efficiency will improve substantially, and a later baseline year will more accurately represent the industry; earlier years give a large bias towards much higher carbon intensity for corn-ethanol. In order to accurately reflect the current technology used by ethanol producers, the baseline for LCFS evaluation of corn-based ethanol should be 2007 or later.

A study conducted by the University of Illinois at Chicago assesses emerging technologies that reduce the energy consumption and the Global Warming Impact (GWI) of corn ethanol production. These new technologies have emerged for corn production as well as for ethanol processing at the biorefinery. The study documents that many ethanol plants have already adopted energy and carbon footprint reducing technologies including:

- no-till farming;
- corn oil extraction;
- dry fractionation;
- cold cook processes;
- advanced motors;
- combined heat and power systems;
- anaerobic digesters;
- biomass combustion/gasification systems;
- GPS and Auto-Steer systems in farm equipment;
- slow release fertilizers;
- nitrification inhibitors;
- N-application based on soil testing and remotely sensed imagery;
- N-side dressing

In summary, a total of 25 out of the 160 operating ethanol plants in the US, or 16 percent, have adopted one or the other of the described technologies.

(CO2STAR, GE3, ICM3, ILCORN, IRELLC, NCB, NCERC2, NCSU, UNICA, VALENTE)

Response: The carbon intensity values generated for corn ethanol using CA-GREET take into account average industry-wide data inputs for farming practices, crop collection and transportation, fuel production, co-product generation, and distribution of fuel. The data used in the fuel pathway analyses was from the most recent version of GREET updated, as appropriate, with more current data from various sources such as industry groups, USDA, and U.S.EPA. The individual pathways for corn ethanol in the Lookup Table are differentiated based on four factors; location of the production facility (California or Midwest), type of corn milling (wet or dry), type of distillers grains produced (wet or dry), and source of fuel for heat energy and co-generated electrical power (natural gas, coal, or biomass). Producers whose energy use data are different from the values used in the development of the fuel pathways or producers whose process deviates substantially from that of the pathways represented in the Lookup Tables can propose their own pathways according to Methods 2A and 2B. A document is being developed that will provide guidance to the stakeholders on the implementation of Method 2A and 2B provisions. In addition, when emerging technologies become industry-wide practice, the technological advancements can be integrated into existing fuel pathways. The Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014. These and subsequent program reviews will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate. Section 95489(a) requires that these reviews consider “advances in fuels and production technologies.”

K-2. Comment: CARB fails to acknowledge and incorporate in the LCFS rulemaking a variety of ongoing and emerging technical advances that continue to improve ethanol’s fuel cycle energy balance and carbon footprint. For example, CARB ignores significant progress taking place in the Netherlands with hydrous ethanol, which is being shown to effectively replace today’s anhydrous ethanol specification with attendant cost, energy and carbon emission reductions. A fairer more progressive approach by CARB would at least take note of and examine advances like this that stand to enhance the ethanol fuel cycle. Others, including the State of Louisiana, have moved to test and evaluate hydrous ethanol. (MDSA)

Response: The LCFS is intended in part to promote the use of biofuels and also encourages the technological advances in fuel infrastructure and vehicle production required to support their use. As mentioned in the response to Comment K-1, producers who incorporate emerging technological advances which reduce the lifecycle emissions may use Methods 2A and 2B to establish a pathway-specific carbon intensity value. As for hydrous ethanol, this fuel is not approved for use in California at the present time.

K-3. Comment: The technological improvements I outlined above were made possible by a government that recognized the significant benefits of ethanol for

our environment, national security and economy. They set the goal; we met it and then surpassed it. We would still be in the age of inefficient, farm-scale ethanol plants if not for the visionaries at every level of government who prompted efficiencies. The only way to continue these breakthroughs to develop the ethanol of tomorrow is to maintain a strong ethanol industry today and entice it to grow even further.

POET is not requesting special preference for our products. We are simply requesting the level playing field promised as part of the LCFS and that CARB hold ethanol to the same carbon accounting standard as petroleum, hydrogen, electricity, and all other fuels.

The ethanol industry has made tremendous strides in not only helping our environment, but reducing our reliance on foreign oil and helping our nation's economy. CARB should refrain from derailing those benefits with a well-intentioned but significantly flawed policy. (POET1)

Response: The LCFS provides a level playing field for all regulated parties. See responses to Comments L-68, L-75, L-76, and K-1.

K-4. Comment: We also have concerns with CARB's determination of some of the direct emissions for corn ethanol, and have research programs that are starting to address some of these issues. However, one overarching concern here is that the direct emissions are typically based on agricultural and ethanol production data collected in the 2001-2006 timeframe. CARB selected the baseline year for the LCFS as 2010, and it is very likely many of these inputs will change dramatically from the levels assumed in the CA-GREET model. This will have a significant effect on the direct emissions. Thus, we believe CARB must update the direct emissions analysis to 2010 to be consistent with its chosen baseline year. (RFA1)

Response: The data used in the fuel pathway analyses was from the most recent version of GREET updated, as appropriate, with more current data from various sources such as industry groups, USDA, and U.S. EPA. As to changes in inputs in the future, ARB continues to evaluate data related to calculating direct emissions and will modify fuel pathways when it is appropriate to do so. The Board requires two mandatory program reviews to be completed in 2011 and 2014. These and subsequent program reviews will facilitate the updating of fuel pathways with the most recent data.

The baseline carbon intensity used for determination of the compliance schedule was approved by the Board at the April 23, 2009 hearing and is fixed. This baseline value can only be changed by a full regulatory process. Moreover, the fact that data used for lifecycle assessment modeling is a few years old cannot be avoided. To update carbon intensity values, agricultural and industrial surveys need to be completed and data needs to be reviewed. Modeling then needs to be completed with the new data and the results approved through the regulatory process. This all takes time. Since ARB has

chosen to base the lifecycle assessment calculations on real verifiable data rather than future predictions, our assessments will, by necessity, be a couple years out of date.

K-5. Comment: I respectfully ask that you look behind the science being presented and to the motivations of those offering recommendations. The same forces that prevailed in Proposition 87 have been joined by those who will benefit from lower corn prices if starch-based ethanol is set back and by those whose opinions are founded on the past performance of the starch-based ethanol industry without knowing of the many advances underway. For example, the media never reports the fact that at its peak in 1932, U.S. corn acreage approached nearly 120 million acres, nearly all of which was used to feed draft animals (in other words, for fuel). This year, U.S. farmers will plant approximately 84 million acres to corn (nearly a 50 percent reduction), and most of that corn will be used to feed livestock. Despite the critic's unfounded claims of sod-busting and other land degradation charges, it is clear that American farmers' productivity is more than keeping pace with demand for food, feed, fuel, and fiber. (BCC2)

Response: Current farm productivity is used in the fuel pathway assessments and improvements in farm productivity will be included in updated carbon intensity values of biofuels. See also the responses to Comments K-1, K-4, and L-40.

K-6 Comment: We believe that standards need to be based on sound, peer-reviewed and updated, scientifically based data and we don't believe that the proposed regulations achieve this because of these factors:

- A recently released peer reviewed publication in the *Journal of Industrial Ecology* titled Improvements in Life Cycle Energy Efficiency and Greenhouse Gas Emissions of Corn-Ethanol has shown that corn based ethanol reduces direct greenhouse gas (GHG) emissions by 48%-59% as compared to gasoline. California LCFS tables do not reflect this peer reviewed information.
- The adoption and usage of data of current production practices, input efficiencies and yield are missing. According to various National Agriculture Statistics Service and Economic Research Service reports, yield is increasing at a much faster pace than previously predicted. Growers have also increased fertilizer efficiency greatly over the past thirty years. Unfortunately, the CA-GREET model does not incorporate all of these yield advances and improved efficiencies.
- Updated feeding rates of co-products and their adjusted credits. Dr. Michael Wang, et al. in September, 2008 released up to date feeding and displacement ratios for distillers grains. The update shows that for each pound of distillers grains that is placed in a ration, it replaces 1.28 pounds of conventional corn and soy-based feed. This displacement is greater than the current ration CARB is using and the new data should be incorporated into the model. (MCGA)

Comment: Efficiency of use of commercial nitrogen fertilizer per bushel of corn

produced will likely continue to improve from the current level of 0.9 pounds per bushel. The improved efficiency would reduce the amount of nitrous oxide (N₂O), a greenhouse gas, released per bushel of corn produced. Continuation of the current trend of less use of anhydrous ammonia would also reduce the amount of N₂O released in corn production. Commercial applications of phosphate and potash per bushel produced are also expected to decline, but not continue at the trend decline of the last 25 years. (ILCORN)

Response: With respect to advances in farming and ethanol production practices as well as improvements in data accuracy, please see responses to Comments K-1 and K-4. In summary, ARB will continue to monitor industry-wide improvements in farming practices, including fertilizer use and crop yields, and will adjust the model inputs (and carbon intensities) as necessary. The Board requires two mandatory program reviews to be completed in 2011 and 2014. These and subsequent program reviews will facilitate the updating of fuel pathways with the most recent data. Moreover, producers whose energy use data are different from the values used in the development of the fuel pathways or producers whose process deviates substantially from that of the pathways represented in the Lookup Table can propose their own pathways according to Methods 2A and 2B.

With respect to credit given for distillers grains co-product, see Appendix C11 in the ISOR and the response to Comment M-1

K-7. Comment: Nitrification inhibitors work by retarding the formation of nitrate by nitrifying bacteria. A publication by Dow researchers in the Journal of Nutrient Cycling in Agroecosystems asserts that “greenhouse gas emissions decreased by 51 percent” with the application of nitrification inhibitors. (ILCORN)

Response: Staff used data from the USDA for the nine states in the Mid-West to calculate farming impacts for the corn ethanol pathway. These were for average farming practices used in these nine states. As for changes in farming practices, ARB will continue to monitor improvements in such practices, including fertilizer use, and will adjust the model inputs (and carbon intensities) when changes become widespread practice. To our knowledge, the use of nitrification inhibitors by corn farmers is not currently common practice. The Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014, which will provide opportunities to monitor developments related to all stages of fuel production and make CI adjustments when they are appropriate.

K-8. Comment: In our previous comments on CA-GREET (dated June 27, 2008), we noted that the lime application rate assumed in the model of 1202 g/bu/year is far too high, and a better estimate of lime application rates was about 87.4 g/bu/year, based on the recent work by Kim and Dale. The latest CA-GREET model still assumes 1202 g/bu. What is the basis for maintaining this assumption when better data exists to guide the parameter? (RFA1)

Response: The CA-GREET model used data published by the USDA for nine states in the Mid-West that produce corn to calculate farming impacts for corn ethanol. The data published by federal agencies such as the USDA, which is frequently used by the Argonne GREET model, has been used as data representative of average farming practices. The value of 87.4 g/bu/year being cited from Kim and Dale is for no-till corn farming practice but the values used in the ISOR analysis considers average of various practices and not just one specific agricultural growing practice. The Expert Workgroup being established per the direction of the Board in Resolution 09-31 may consider more sustainable farming practices such as no-till among the various issues that will be reviewed for refinement. This group will report back to the Board by December 2010. Furthermore, the Board has directed staff to work with interested stakeholders to present a plan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation. The benefits of improved farming practices such as no-till may be addressed within the sustainability provisions. See also response to Comment K-1.

K-9. Comment: When these adjustments are made, corn ethanol will have a significantly lower overall carbon intensity value than baseline gasoline. Because of this, we encourage ARB to revisit its decision to use 2010 E10 as the baseline gasoline. Inclusion of 10% corn ethanol in the baseline gasoline formulation forces corn ethanol to compete against itself, rather than petroleum fuels with higher carbon intensity. Several months ago, when ARB anticipated that the LUC emissions value for corn ethanol could be very high, it changed baseline gasoline (from which the 10% LCFS carbon intensity reduction is estimated) from 2006 (with 5.7% ethanol) to 2010 (with 10% corn ethanol). We assume the purpose behind this change in the baseline year and gasoline formulation was to prevent penalizing oil companies for the possibility of increasing carbon intensity values between 2006 to 2010 due to the implementation of E10 in 2010. The transition to E10 in 2010 is largely expected because of changes in the Predictive Model. However, if ARB finds that the carbon intensity of corn ethanol is less than gasoline (due to justifiable adjustments to LUC and GREET analyses), this change in baseline date is not justified or desired, because increasing ethanol content from E5.7 to E10 would actually reduce overall blend carbon intensity. (RFA1)

Response: The baseline is 2010 includes 10 percent ethanol to reflect the ethanol content in CaRFG that will exist in January 2010. In evaluating the baseline carbon intensity, it was determined that the baseline value was basically the same whether 5.7 percent or 10 percent ethanol was used. Ten percent ethanol was also used because the predictive model in the CaRFG regulations as amended in 2007 requires that increases in evaporative hydrocarbons from the use of ethanol be mitigated. This can be done by using no ethanol or using more than the current 6 percent ethanol. Due to the Federal requirements to use more ethanol, producers are electing to use this approach. The consideration of the 2010 timeline was based on the Governor's Executive Order and not to satisfy any other requirement.

K-10. Comment: Several months ago, when ARB anticipated that the LUC emissions value for corn ethanol could be very high, it changed baseline gasoline (from which the 10% LCFS carbon intensity reduction is estimated) from 2006 (with 5.7% ethanol) to 2010 (with 10% corn ethanol). We assume the purpose behind this change in the baseline year and gasoline formulation was to prevent penalizing oil companies for the possibility of increasing carbon intensity values between 2006 to 2010 due to the implementation of E10 in 2010. The transition to E10 in 2010 is largely expected because of changes in the Predictive Model. However, if ARB finds that the carbon intensity of corn ethanol is less than gasoline (due to justifiable adjustments to LUC and GREET analyses), this change in baseline date is not justified or desired, because increasing ethanol content from E5.7 to E10 would actually reduce overall blend carbon intensity. Therefore, commensurate with ARB making reasonable changes to the LUC emissions estimate for corn ethanol, we request that the baseline return to 2006 and E5.7. The impetus for this change is further supported by the Governor's Executive Order S-01-07, which suggested the 10% reduction in carbon intensity should be relative to 2006 carbon intensity levels. (RFA1)

Response: See response to Comment K-9.

K-11. Comment: Energy assumed for lime is too high. We still have concerns with the lime application rates and the assumed lime types (whether it is applied as limestone or CaCO_3), and are reviewing these assumptions as well. Since GREET assumes all of the carbon in lime eventually reacts to form CO_2 , this is an important area. (RFA1)

Response: See response to Comment K-8.

K-12. Comment: CARB GREET does not reflect agriculture practices that affect direct GHGs for baseline year of 2010. According to the CARB GREET model, about 35% of the energy used in corn farming is for diesel fuel used to operate equipment during farming operations, and farming GHG represents 14% of total direct GHGs from corn ethanol. Thus, the use of diesel fuel for farming operations represents 5% of total direct GHGs. An increasing trend in corn farming is no-till or low-till practices. This would significantly reduce diesel fuel consumption. It is unclear from the report what level of no-till practices are assumed in the direct CI values, and whether those are representative of no-till farming practices in the base year for the LCFS, which is 2010. This area should be examined. Also, agriculture chemical production and use account for 41.2% of total direct GHGs from corn ethanol, and N_2O emissions from nitrogen fertilizer accounts for half of this 41%, or about 20%. The use of cover crops almost completely offsets N_2O emissions from fertilizer, according to recent research from Kim and Dale. The California GREET model for ethanol may assume no use of cover crops, so N_2O emissions could be overestimated in GREET based on this factor. RFA is conducting additional research in this area. (RFA 1)

Response: Corn farming energy and GHG emissions are calculated in the GREET technical assessment documents based on current data from USDA. The data are based on a survey of agricultural practices in nine corn producing states in the Midwest. To the extent that more sustainable farming practices are implemented on an industry-wide basis, there are two mandatory program reviews in 2011 and 2014, at which time these new practices could be incorporated into the pathway assessments. The Expert Workgroup being established per the direction of the Board in Resolution 09-31 may consider the issue of sustainable farming practices among the various issues that will be reviewed for refinement. This group will report back to the Board by December 2010. Furthermore, the Board has directed staff to work with interested stakeholders to present a plan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation. The benefits of improved farming practices such as no-till and the use of cover crops may be addressed within the sustainability provisions. See also response to Comment K-4.

K-13. Comment: Regarding the issue of ethanol plant type in the baseline, as indicated in Section 5, CARB has selected a 2010 base year for estimating the 10% LCFS reduction. So, what matters is the mix of plant types in 2010, not some other year like 2008 or 2006. For this reason, we believe that CARB must estimate the plant types providing ethanol in 2010 to properly determine the starting CI of ethanol for the LCFS reduction. The values that are currently being used will be out-of-date and inappropriate by 2010. (RFA1)

Response: The baseline carbon intensity used for determination of the compliance schedule was approved by the Board at the April 23, 2009 hearing and is fixed. This baseline value can only be changed by a full regulatory process. Moreover, the fact that data used for lifecycle assessment modeling is a few years old cannot be avoided. To update carbon intensity values, agricultural and industrial surveys need to be completed and data needs to be reviewed. Modeling then needs to be completed with the new data and the results approved through the regulatory process. This all takes time. Since ARB has chosen to base the lifecycle assessment calculations on real verifiable data rather than future predictions, our assessments will, by necessity, be a couple years out of date.

K-14. Comment: CARB has selected the baseline year for the LCFS as 2010. The GREET model CI for corn ethanol is based in large part on farm survey data conducted in the 2001-06 timeframe. The use of old survey data should not carry-over into 2010, without adequate validation. CARB must update the direct CI values for corn ethanol for the year 2010 to be consistent with the baseline year for the LCFS. (RFA1)

Response: See response to Comments K-4, K-9, and K-12.

K-15. Comment: On page IV-11 of the Staff Report dated March 5, 2009 at the top of the page, the report states that a survey of farming practices in several corn farming regions was conducted to assess average energy use on farms. It would

be more appropriate to assess average energy use for corn farming in the corn production region of the U.S. Two technologies are also important to evaluating energy use; no-till farming and corn biotechnology. Both of these technologies have spread rapidly over the past 10 years in the Corn Belt and they both use less energy in corn production than “average.” The mechanism by which lower energy use is achieved through these technologies is that they require fewer passes over the field during the growing season and less chemical pesticide use. It does not appear that these effects of these technologies on energy use figure into this analysis. (NCSU)

Response: While no-till farming and corn biotechnology are more common than in the past, they still do not dominate farming practices. When they do dominate and define the “average”, they can be recognized and the corn to ethanol pathways can be appropriately adjusted as part of the mandatory program reviews. Also, see the responses to Comments K-4 and K-12.

K-16. Comment: The CARB staff should note as well the recent release of a report by the International Energy Agency (EIA), “An Examination of the Potential for Improving Carbon/Energy Balance of Bioethanol,” Report T39-TR1, 15 February 2009. This report develops direct GHG emissions for corn ethanol substantially lower than the CARB staff with CA-GREET, and looks for greater improvement in the future. (PRX)

Response: We recognize that there are various reports estimating the GHG emission of corn ethanol using different models. Each report and model uses different inputs and assumptions. In October 2007, ARB selected the Argonne GREET model and modified it to reflect California inputs and assumptions. The CA-GREET model utilizes data from USDA, U.S. EPA, and other publicly available government based sources for calculating the carbon intensity of each fuel. It has been transparent and supported by numerous technical reports shown on the Argonne website. The inputs and assumptions were discussed at the public workshops and, in response to comments received from stakeholders, appropriate refinements have been incorporated into the CA-GREET. As for specific producers that can provide verifiable documentation of process improvements, they can propose their own pathways via Methods 2A and 2B. Moreover as technological improvements become employed on an industry-wide basis, existing fuel pathways will be updated to reflect these changes. Mandated program reviews in 2011 and 2014 as well as subsequent reviews will facilitate these updates.

K-17. Comment: The CA-GREET model assumes a static value for direct land-use emissions. As with the other parameters, there is no adjustment factor for future improvements in land use and Method 2A of the Proposed Regulations does not expressly authorize the use of industry-wide data on land use to supplant the data inputs in CA-GREET. (NOVOZYM1)

Response: We agree that the CA-GREET is a static model that uses current values and data to estimate direct land use emissions. As improvements to farming practices

(direct land use practices) become adopted industry-wide, ARB will update fuel pathway assessments to reflect these improved practices. The Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014. These and subsequent program reviews will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate.

K-18. Comment: On the electric side, the hammer mills in traditional dry mill processes are replaced by roller mills. Two manufacturers report that their dry mill fractionation process requires about 1 kWh/gal electricity. (ILCORN)

Response: See the response to Comment K-1.

K-19. Comment: ConocoPhillips recommends that CARB incorporate the recent results (preliminary) from the NREL/Iowa State University/ConocoPhillips study regarding the production of cellulosic ethanol from corn stover. (CONOCO)

Response: The results mentioned above from the NREL/Iowa State University/ConocoPhillips study for cellulosic ethanol have been presented as preliminary. ARB will be working with stakeholders to develop Lookup Table values for cellulosic ethanol taking into account different cellulosic feedstocks. Data from studies such as that mentioned in the comment will be considered during this process. Individual producers can also provide verifiable data to support the inputs to the CA-GREET model via Method 2A or 2B and establish a carbon intensity for their process. These pathways will include both direct and indirect effects, if appropriate.

K-20. Comment: The ICM/Econergy Model has been used to generate life-cycle emission profiles, or Global Warming Intensity (GWI) values, for conventional dry-grind corn and milo (grain sorghum) ethanol plants existing today, as well as for the advanced dry-fractionation plants of the immediate future. A recently released peer reviewed publication in the Journal of Industrial Ecology titled Improvements in Life Cycle Energy Efficiency and Greenhouse Gas Emissions of Corn-Ethanol has shown that corn based ethanol reduces direct greenhouse gas (GHG) emissions by 48 percent -59 percent as compared to gasoline. But CA LCFS look-up tables don't reflect this peer reviewed information. (ICM3, IOWACORN, MCGA, NCB)

Response: The ICM/ Econergy is a private ICM company-owned model compared to the CA-GREET which is a public domain model. Although different models may yield different results based in part on the different assumptions used in the models, ARB chose to use CA-GREET because it is peer-reviewed, widely used, well understood, and well documented. Also, many studies only report the impacts of direct effects and do not account for land use change effects. ARB's analysis does include a 30 gCO₂e/MJ impact to corn ethanol attributable to land use change effects (for justification, see ISOR Chapter IV and response to Comment K-181). Inclusion of land use change effects to the direct effects does increase the pathway carbon intensity for corn ethanol and could be another factor that the Lookup Table values are higher than

that from the study being referenced by this commenter. In approving the staff recommendation as detailed in the ISOR, the Board recognized that the analyses rely on data that will continue to improve. To assure that we are using the most recent verified data, we have been directed to do periodic reviews, as mentioned in response to Comment K-1. These and subsequent program reviews will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate. The Board also directed staff to establish an Expert Workgroup. This group will evaluate the land use change analysis presented in the ISOR and recommend any refinements by the end of December 2010.

K-21. Comment: Similarly, there is substantial variation in the GHG emissions intensity of corn-ethanol due to bio-refinery design and location. The failure to adequately account for regional differences in production is more significant than might first appear because production inputs constitute a large part of GHG emissions and production inputs can vary greatly. Based on state averages for crop yields and management, crop production represents 37 to 65 percent of total life-cycle GHG emissions. The model's failure to adequately address these regional differences severely undermines the scientific accuracy of the proposed regulation as applied to corn ethanol. (GE3)

Response: The CA-GREET model utilizes survey data and other sources of information from the USDA and other agencies as inputs to the model for the various parameters used to calculate the carbon intensity for corn ethanol. The agricultural, energy, and other inputs are weighted averages across the corn producing region of the Midwest. As improvements to farming practices (direct land use practices) become adopted industry-wide, ARB will update fuel pathway assessments to reflect these improved practices and new data. The Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014. These and subsequent program reviews will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate. Smaller scale regional differences in farming practices will not be recognized. See also the response to Comment K-1.

K-22. Comment: The CA-GREET model for Life-Cycle GHG emissions, which utilizes outdated and inaccurate inputs related to farming and ethanol production, is insensitive to critical geographic differences in corn and ethanol production that greatly affect the total life-cycle GHG emissions, and which produces a flawed co-product calculation that substantially underestimates the environmental value of dry distiller's grain with solubles (DDGS). These errors and limitations serve only to exacerbate the highly discriminatory carbon intensity score for ethanol fuels. They also add further questions about the overall technical rigor of ARB's methodology for such highly sensitive calculations. Finally, the calculation of the net increase in corn acreage needed to meet the projected level of corn use for ethanol must recognize that 30 percent of the raw corn used for ethanol production is not consumed in the distilling process, but is available as a livestock feed. That availability substitutes for other feeds, including corn,

reducing the acreage required for the production of those feeds. (GE3, UIUC1)

Response: With respect to outdated and inaccurate inputs related to farming and ethanol production see response to Comment K-1. With respect to geographical differences that affect lifecycle emissions see response to Comment K-21. DGS produced from the corn ethanol production process is appropriately treated as a GHG credit in the analysis presented in the ISOR. This credit is allocated both in the CA-GREET and GTAP models. In approving the staff recommendation as detailed in the ISOR, the Board directed staff to establish an Expert Workgroup. This group will re-evaluate the land use change analysis presented in the ISOR and recommend any refinements by the end of December 2010. The Board has also mandated two program reviews to be done in 2011 and 2014 at which time any refinements based on updated data could be considered. See also Appendix C11 in the ISOR and the response to Comment M-1 for additional details on co-product credits for DDGS.

K-23. Comment: It is very disturbing to see California produced ethanol from corn receiving a higher energy ratio because of improvements in processing. These improvements are slight and actually lower the value of the distiller's grains. As more energy is obtained from a kernel of corn, less energy remains for the byproducts. You can't add to one without subtracting from the other but this was apparently done for California based ethanol. (AIR)

Response: The carbon intensities for California-produced ethanol reflect the differences in California ethanol production and processing, the differences in California electric utilities, and the use of biomass as a fuel in California facilities. With respect to the issue of credit for distillers grains, the carbon intensity assessments for all corn ethanol pathways assume that distillers grains will substitute as an animal feed for corn on a pound for pound basis. The rationale for this assumption is presented in Appendix C11 of the ISOR and in the response to Comment M-1. Recognizing the controversy over this assumption, the Board directed staff to convene an expert workgroup to assist the Board in refining the land use analysis for biofuels. The topic of proper credit to be given for co-products will be addressed by the workgroup. ARB will seriously consider the findings of the workgroup on this topic.

K-24. Comment: The energy inputs for biocatalyst (enzymes) production should be included. These enzymes can not be regenerated post fermentation processes, and need to be constantly replenished. (CONOCO)

Response: The CA-GREET methodologies include the energy for production of enzymes.

K-25. Comment: The California-modified GREET pathway for corn ethanol inaccurately measures carbon intensity values in a variety of significant ways, including use of undocumented assumptions, lack of transparency of analysis and reliance on outdated farming and ethanol production data; underestimating the co-product credit for corn-based ethanol and failing to account for regional

differences in corn production inputs. There is a large difference between California; dry mill; wet DGS pathway and Midwest; dry mill; wet DGS pathway. I have not been able to locate the pathway for California ethanol and thus not wanting to assume why the large difference, I believe you have not been completely open and upfront on disclosing of information. (GE3, IOWACORN, NCB)

Response: The Argonne National Laboratory's GREET model is the model used for the LCFS. All of the inputs for the GREET model are supported with documentation. Argonne's documentation is provided in several papers, reports, and journal articles. This model was modified to include California specific factors, such as California electricity, etc. For each of the pathways that the CA-GREET model was used in order to develop a CI value, a detailed pathway document was prepared. The documents include the details of the methodologies, inputs, calculations, and detailed references for the sources of information. The Corn Ethanol Pathway document used in the regulation may be found at http://www.arb.ca.gov/fuels/lcfs/022709lcfs_cornetoh.pdf. This document provides complete details for all the steps in the WTW analysis for Mid-Western dry mill and wet mill produced from corn ethanol. Although this document does not include detailed calculations for the California-modified corn ethanol pathway, it does demonstrate how an interested party may use the CA-GREET v1.8b model (<http://www.arb.ca.gov/fuels/lcfs/lcfs.htm>) to calculate the carbon intensities for all of the other pathways in the pathway document. See also responses to Comments K-1, K-21, and K-23.

K-26. Comment: For gasoline CI reductions, staff has not yet provided CI factors for cellulosic ethanol or advanced renewable ethanol, which our members need for compliance purposes. (WSPA1)

Response: Staff is in the process of developing the full fuel lifecycle document for cellulosic ethanol. This information should be provided well in advance of compliance initiation. Producers also have access to Methods 2A and 2B to establish new pathways.

K-27. Comment: It is almost impossible to analyze the economic impact of the LCFS, since key components of the regulation are still missing (such as the CIs for many of the fuel pathways). Therefore, we can't calculate how much of what kinds of fuels might be used to comply, whether there will be sufficient supplies, and what the cost impact might be. (WSPA1)

Comment: We are very concerned that ARB currently does not have any CI pathways completed for biodiesel, advanced renewable biodiesel or renewable diesel relative to the diesel silo. According to the scenarios developed by staff, these three fuels are supposed to provide 94%-100% of the diesel CI reductions, but we have no currency with which to formulate our plans for the program. Similarly, for gasoline CI reductions, staff has not yet provided CI factors for

cellulosic ethanol or advanced renewable ethanol, which our members need for compliance purposes. (WSPA1)

Response: Several fuel pathway documents for ethanol and biodiesel have been developed and posted on the LCFS website. These pathways represent fuels that may be used to comply with the LCFS. The pathway for soy biodiesel will soon be completed and posted for public comments. Considering that compliance with the LCFS is not required until January 1, 2011, we expect that additional potential fuels will be evaluated by then. Additionally, several compliance scenarios and their costs can be located in the ISOR (Chapters VI and VIII and their corresponding appendices). These scenarios demonstrate that compliance can be achieved in the early years with the fuel options that are currently available. With respect to the availability of pathway documents for cellulosic and advanced renewable ethanol, see response to Comment K-26.

K-28. Comment: CARB should adopt a verifiable mechanism that ensures best carbon mitigating practices are rewarded on a timely manner so as to ensure quicker adoption. Merely updating CA-GREET model in hindsight (three years as has been suggested in public hearings) will not be enough to reach the objectives of California's forward-looking climate change policy. (UNICA)

Response: The Method 2A and 2B processes were designed to provide a fairly responsive and timely mechanism for regulated parties and fuel producers to obtain carbon intensity values for both new pathways and substantial changes to existing pathways. A document is being developed that will provide guidance to the stakeholders on the implementation of Method 2A and 2B provisions. In addition, when emerging technologies become industry-wide practice, the technological advancements can be integrated into existing fuel pathways. The Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014. These and subsequent program reviews will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate. Section 95489(a) requires that these reviews consider "advances in fuels and production technologies."

K-29. Comment: A UN energy report concluded that "In general, crops that require high fossil energy inputs (such as conventional fertilizer) and valuable (farm) land, and that have relatively low energy yields per hectare, should be avoided..." Corn-based ethanol clearly meets all of these prohibitive criteria; corn uses the most conventional fertilizer, "requires the highest quality farmland," and yields little energy per acre planted. The current lifecycle analysis fails to account for GHG emissions from the following sources:

- Increased fertilizer and pesticides use to gain higher corn yields must be accounted for in biofuel pathways.
- The energy used to move water to process biofuels.
- Equivalent CO₂ emissions of particulate black carbon (BC), the second-

leading cause of global warming. BC has a global-warming potential of 90-190 times that of carbon dioxide. The largest sources of BC in the U.S. are agricultural equipment, construction machines, diesel trucks, and ships all of which are used in the corn-ethanol process.

- CO₂, BC, CH₄, and N₂O emissions associated with transporting ethanol by rail, truck, or barge from the Midwest to coastal areas. These emissions must be evaluated for their contributions to GWI values for all biofuel and diesel blends.

Most ethanol plants have traditionally used natural gas to power their operations, but as this becomes more expensive, some are switching to coal... Because coal fired plants are not as energy efficient as natural gas-fired plants (and also release more pollutants during combustion), the ethanol produced from coal plants loses the potential climate benefits that come from using gas plants and can actually contribute to global warming. (CERA2)

Response: The CA-GREET model accounts for fertilizer, pesticide, and water use required to achieve current crop yields. The lifecycle assessment modeling does not, however, account for increased use of fertilizers, pesticides, and irrigation resulting from the price-induced intensification of all crops (an indirect effect of expanded biofuels production). The Board continues to evaluate these and other indirect effects with intent of quantifying and incorporating all significant direct and indirect emissions. Furthermore, the Board has directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. Intensification of farming practices will likely be a topic evaluated by this workgroup.

Assembly Bill 32 does not include black carbon in the list of greenhouse compounds to be monitored and regulated. Also, the scoping plan does not include the effects of black carbon. Therefore, black carbon was not included in the LCFS lifecycle assessment modeling. We agree that the potential greenhouse effects of black carbon warrant further investigation and we will continue to evaluate the scientific literature on this topic.

The pathway assessments do include CO₂, CH₄, and N₂O emissions associated with transporting ethanol from the Midwest to California. As acknowledged above, black carbon is not included.

If a producer switches from natural gas to coal power, fuel produced at the facility will no longer qualify for the lower carbon intensity associated with natural gas powered production. The producer will have to use an existing carbon intensity value from the lookup table for production using coal power or propose a modified pathway value using Method 2A. We do not, however, expect ethanol produced using coal power to be used in California under the LCFS.

K-30. Comment: I am writing to you on behalf of Illinois River Energy, LLC (IRE); a fuel ethanol producer located in northern Illinois. As a company founded on the

principle of the importance of renewable energy to the future of our society, we applaud the commitment that California has made in reducing its environmental impact. We are concerned, however with the inaccuracies regarding the comparison between gasoline and corn based fuel ethanol in the data being utilized to make recommendations to the CARB via the proposed LCFS. We believe these inaccuracies, resulting in the reduction of corn based ethanol will have a negative impact on global warming. (IRELLC)

Response: With regard to differences in direct emissions between the appropriate pathway listed in the Lookup Table and those of the IRE production facility, please see the response to Comments K-1 and K-21. With respect to land use change emissions please see response to Comment L-62.

K-31. Comment: No corn will be grown in California for corn ethanol. The water needed would never justify the use. It takes at least 2000 gallons of water to grow enough corn for one gallon of ethanol. The fact that most of the corn will come from states such as Colorado and Nebraska for California ethanol plants is also not considered in the GREET analysis. Irrigation needs for crops in these states are much higher than the average value of energy needed for growing corn across the Midwest. (AIR)

Response: The lifecycle assessment for California corn ethanol accounts for the importation of corn from other states in order to meet the needs of California ethanol plants. The pathway document assumes that most of the corn will be supplied by the nine state region of the Mid-Western United States and used appropriate USDA data for farming inputs including an average water use for corn crop irrigation for this region. These data inputs for farming emissions are the same as those used for ethanol produced in the Midwest. The lifecycle assessment also accounts for emissions associated with transportation of the corn from this region. ARB has decided not to differentiate between farming practices and yields for crops grown in different regions of the Midwest. Also, see Section F for other water use responses.

K-32. Comment: CARB's Life Cycle Analysis for corn ethanol estimates only 75 to 90 gCO₂Eq/MJ, which compared to the Universities calculations is an underestimate ranging from 11 percent to 166 percent. (CBE3)

Response: Although different models may yield different results based in part on the different assumptions used in the models, ARB chose to use CA-GREET and GTAP because they are peer-reviewed, widely used, well understood, and well documented. As we indicated in the ISOR, we believe that ARB's analysis for corn ethanol is a conservative approach. Some commenters have argued that the CI should be much higher while others have argued that it should be much lower. The Board has directed the Executive Officer to establish an Expert Workgroup to further evaluate the land use change and other lifecycle analysis issues and report back with recommendations by December 2010.

K-33. Comment: The current lifecycle analysis fails to account for GHG emissions from the following sources:

- Climate impacts from nitrous oxide have been highlighted recently in a paper by Nobel prize winner Paul Crutzen and others who suggest that nitrous oxide emissions from nitrate fertilizers have been underestimated in biofuel greenhouse gas emissions calculations. Crutzen challenges the IPCC estimate that just 2% of nitrogen which is applied to soils in the form of nitrate fertilizers is transformed by soil microbes into nitrous oxide arguing that after comparing the increase in nitrous oxide in the atmosphere to the known inputs by humans, and accounting for changes due to deforestation, that 35 percent of nitrate fertilizers must be converted to N₂O. However, most life-cycle studies for biofuels also wrongly ignore part of the IPCC figure - they consider the approximately 1 percent of direct emissions from the field where the fertilizers are applied but ignore 1 percent indirect emission from the much wider area which will be “fertilized” through rainfall and runoffs from fields. (CERA2)

Comment: Evidence provided by Paul Crutzen, Howarth et al., and Searchinger et al., among others, that indirect nitrous oxide emissions from agrofuels linked to the use of nitrogen fertilizer, or from legume monocultures, are far higher than suggested by IPCC methodology has not been fully assessed, nor has it been addressed in any way by the IPCC. This alone means that there is no scientifically credible way of calculating life-cycle greenhouse gas emissions from agrofuels. (CAPOZ)

Response: The analysis presented in the ISOR and approved by the Board used a factor that is consistent with Argonne’s analysis of N₂O emissions directly attributable to application of fertilizers in agricultural soil. Crutzen’s analysis provides a summation of total N₂O in the atmosphere from various sources of which agricultural N₂O is only one component. We acknowledge the large uncertainty associated with estimating N₂O emissions and the large contribution these emissions have on the carbon intensity. To take advantage of advances in science and other information, the Board mandated two program reviews to be done in 2012 and 2015 when refinements could be considered. Furthermore, the Board has directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. The uncertainty over N₂O emissions resulting from fertilizer application will likely be a topic evaluated by this workgroup.

K-34. Comment: Specifically, the inclusion of agrofuels (industrial biofuels) threatens to undermine the impact of the regulation and could lead to it actually exacerbating global warming. (CAPOZ)

Response: The LCFS should not exclude the use of any fuels. All fuels are allowed to compete in the marketplace. What the LCFS does is introduce into the marketplace the additional consideration of lifecycle greenhouse gas emissions. Those fuels which are

both economical to produce and also have low greenhouse gas emissions will compete well under the LCFS. Those fuels with large lifecycle greenhouse gas emissions may still be used, but any increase in emissions relative to the compliance standard must be compensated for by increased use of fuels with low lifecycle greenhouse gas emissions. In summary, the LCFS is designed not to dictate which fuels can or cannot be used but rather is designed to introduce the additional consideration of lifecycle greenhouse gas emissions into the decision making process. The LCFS as adopted utilizes well documented, peer-reviewed models to calculate carbon intensities of regulated fuels. These models take into consideration impacts from farming, transportation, feedstock processing, fuel combustion and land use change including both direct and indirect effects. In approving the staff recommendation as detailed in the ISOR and recognizing the uncertainty associated with calculating land use change emissions, the Board directed staff to establish an Expert Workgroup. This group will re-evaluate the land use change analyses presented in the ISOR and recommend any refinements by the end of December 2010.

K-35. Comment: We know from peer-reviewed studies that every industrial agrofuel feedstock is more greenhouse gas emitting than petroleum. The lead author of one such peer-reviewed article, Joseph Fargione, has clearly stated "From a climate change perspective, current biofuels are worse than fossil fuels." (CAPOZ)

Response: Staff analyses, performed using the CA-GREET and GTAP models, do not suggest that from a climate change perspective, all biofuels are worse than fossil fuels. See also the response to Comment K-34.

K-36. Comment: I would like to respond directly to Dr. Sperling's question about the value that CARB has derived for the emissions from conventional biofuels. UCS and other researchers find that the value that CARB is proposing is conservative. A proper accounting could push up the value even higher. As I note in our formal written testimony, there are 3 reasons for this - for why we say the value is conservative, but I can't go into, because I'm running out of time. I think that it's important for CARB, as they move forward with this regulation, to warn convention biofuel producers that they should be aware that the number could go higher in the regulatory review of the program. (UCS5)

Response: In many respects, we agree with this comment. Stakeholders have posed many strong arguments as to why the carbon intensities of biofuels, and especially the land use change carbon intensity, should either be increased or decreased. We believe that the carbon intensity values approved in the Lookup Table are reasonable and were determined in an open, transparent process using the best available data. We do, however, acknowledge that the available methods for estimating indirect impacts (including land use change) are relatively new. As they continue to undergo development, the uncertainty associated with the impact estimates from these methods will decrease. In recognition of the relative infancy of the LUC analysis, the Board directed staff to convene an Expert Workgroup to assist the Board in refining and

improving the land use and indirect effect analysis of transportation fuels. The Board will consider the findings of the workgroup in its continuing efforts to improve the LUC assessment.

K-37. Comment: The planned expansion of biofuels worldwide must be tallied and cumulatively assessed. For example, "Ethanol produced from corn kernels totaled 4.5 billion gallons in 2006. Production is growing rapidly in the United States. China also consumes 3 to 5 million tons of ethanol a year and has [in 2007] setup 4 new processing plants." (CERA2).

Response: While it is always good to be aware of what is happening in total world production, this will have a minor or non-impact on the LCFS. California's total demand for biofuels is expected to be about 3.4 billion gallons per year in 2020. This will be about 10 percent of the biofuel production in the United States under the federal renewable fuel standard (RFS). If the federal RFS is successful, California's share will be adequate for the LCFS. This is discussed in the ISOR (Appendix E at E-15).

K-38. Comment: It is vitally important to note that corn production is becoming increasingly more efficient. Today, through technological advances America's corn growers have the ability to apply fewer inputs to produce larger crops on the same land. Currently it takes about 40 percent less land to grow a bushel of corn than in 1987, and energy used to produce a bushel of corn has fallen by an average of 50 percent. According to Keystone Center's "Field to Market" Report released in January 2009, the production of corn in the U.S. has made significant measurable improvements in reducing energy, water, land use and carbon emissions. U.S. farming practices are advancing and will continue to advance in terms of sustainability and productivity. For example, according to the United States Department of Agriculture (USDA), in 2008 American corn growers produced the second largest corn crop on record and attained the second highest yield per acre in history with fewer energy and fertilizer inputs. (OCGA)

Response: The models used in the fuel pathway assessments take into account current farming practices, crop collection and transportation methods, and crop yields. We agree that crop yields and fuel yields will likely increase in the future and that this will reduce both the direct and indirect land use impacts of using crop-based feedstocks for biofuel production. However, our lifecycle assessments are designed to reflect current technology and agricultural practices and are not meant to predict future technologies or practices. As production technologies and agricultural practices evolve over time, the fuel lifecycle assessments will be periodically updated to reflect these changes. The two program reviews mandated by the Board as well as subsequent program reviews will facilitate these updates.

K-39. Comment: Contrary to Media Reporting, Corn-based Ethanol is Efficient to Produce. The ICM/Econergy Model for a standard ICM dry grind corn ethanol plant illustrates that for every 1.0 unit of primary fossil fuel energy consumed in the ethanol production lifecycle, 1.9 units of energy are available in corn-derived

ethanol. With today's state-of-art fermentation and distillation technology, more efficient enzymes, and optimized fermentation times (40 hours), there is more than just a net benefit in produced energy in comparison to past technologies. The ICM/Econergy full LCA model finds that modern U.S. corn ethanol plants produce fuel ethanol that contains nearly two times the fossil fuel energy that was necessary to produce the ethanol. (ICM2)

Response: Although different models may yield different results based in part on the different assumptions used in the models, ARB chose to use CA-GREET, because it is peer-reviewed, widely used, well understood, and well documented. The specific inputs to the ICM/Econergy model are not available to staff but generally, with the same inputs and assumptions, models will likely generate the same results. As mentioned in the response to Comment K-1, producers of ethanol who incorporate emerging technological advances which reduce the lifecycle emissions have a mechanism to participate into the Low Carbon Fuel Standard using Methods 2A and 2B. These methods will allow producers to develop their pathway -specific carbon intensity values provided they can be supported with verifiable data. See also the response to Comment K-20.

K-40. Comment: Higher stover removal rates would result in greater co-product credits and reduced CI values for corn ethanol. (CONOCO)

Response: Higher stover removal rates and subsequent use in generating process energy may lead to decreased use of fossil fuel in ethanol production. However, increased stover removal rates may lead to increased fertilizer use or reduced crop yields which could offset the benefits of lower fossil fuel use. Further analysis of this practice and the associated effects on lifecycle carbon intensity is required.

K-41. Comment: American farmers have been able to meet the demand for corn because technology has allowed them to grow more on the same amount of land. For example, in 1980, the average corn yield per acre was 91 bushels. In 2008, it was 153.9 bushels. Similarly, ethanol yield has increased from 2.4 gallons per bushel in 1980 to 2.81 in 2007. Had there been no improvements in ethanol and crop yield since 1980, it would have required significantly more land to grow the corn needed for ethanol. As it is, the U.S. planted 84.6 million acres of corn in 1976 and 85 million acres are expected this spring. (GE3)

Response: ARB has used the most recent crop yield data from surveys conducted by the USDA. We agree that crop yields and fuel yields will likely increase in the future and that this will reduce both the direct and indirect land use impacts of using crop-based feedstocks for biofuel production. However, our lifecycle assessments are designed to reflect current technology and agricultural practices and are not meant to predict future technologies or practices. As production technologies and agricultural practices evolve over time, the fuel lifecycle assessments will be periodically updated to reflect these changes. The two program reviews mandated by the Board as well as subsequent program reviews will allow this. See also response to Comment L-40.

K-42. Comment: According to ARB's preliminary work on this issue, it has calculated the carbon intensity of dry mill corn based ethanol to be 67.6 gCO₂/MJ, which is not as good as the University of Nebraska's findings, but is significantly better than calculation for California Gasoline Blendstock of 96.88 gCO₂/MJ. But, when adding the indirect land use change penalty to ethanol, ethanol's carbon intensity jumps to 97.6 gCO₂/MJ. (GE3)

Response: We concur with this comment. The results provided by the University of Nebraska use inputs specific to the local region and also include some methodological approaches that are different from the CA-GREET model thereby resulting in slightly different calculation of direct emissions. As for the indirect land use change impacts, ARB concluded that such impacts are real and worked with UC Berkeley and Purdue to calculate values for these effects. The analysis conducted by UC Berkeley and Purdue indicated that a 30 gCO₂e/MJ GHG impact has to be added to the CA-GREET value (direct impacts) to calculate a total pathway carbon intensity for corn derived ethanol. Hence the total carbon intensity for corn ethanol is higher by 30 gCO₂e/MJ when such impacts are added to the direct impacts.

K-43. Comment: As an example, corn ethanol biorefineries operating in California are the most efficient, least greenhouse gas emitting plants in the country while at the same time they produce a high value feed product for our dairy and beef industries. (AGBC)

Response: See response to Comment K-190.

K-44. Comment: We are submitting this comment regarding the proposed regulation to implement the low carbon fuel standard. It is generally agreed that the rapid expansion in U.S. corn based ethanol use beginning in 2006 has had an impact on crop prices and crop land use patterns in the U.S. (UIUC1)

Response: We agree with this comment.

K-45. Comment: An Analysis of the Projected Energy Use of Future Dry Mill Corn Ethanol Plants (2010 -2030)"; prepared for the Illinois Corn Marketing Board by Steffen Mueller, University of Illinois at Chicago, Energy Resources Center, 10/10/2007

Analysis of potential energy use of future dry mill corn ethanol plants operating between 2010 - 2030.

Addresses current and projected future ethanol plant energy conversion efficiencies based on different fuels, combined heat/power, and other plant process improvements.

Provides summary of 2007 dry mill ethanol plant energy conversion efficiencies, based on various studies and an evaluation of integration of ethanol process

improvements for corn ethanol production. (UIC2)

Response: ARB appreciates the comments and has considered the points raised in this study. As mentioned in the response to Comment K-1, producers who incorporate emerging technological advances which reduce the lifecycle emissions may use Methods 2A and 2B to establish pathway-specific carbon intensity values. In addition, when emerging technologies become industry-wide practice, the technological advancements can be integrated into existing fuel pathways. The Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014. These and subsequent program reviews will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate. Section 95489(a) requires that these reviews consider “advances in fuels and production technologies.”

K-46. Comment: Please use sound science and not the corn based ethanol rhetoric to uncover the true facts about this industry and the overall negative impact it is having on our environment. (VANDEL)

Response: ARB is committed to performing an open, unbiased assessment of the lifecycle impacts of all fuels using the best available data. Please see responses to Comments F-45 and L-104.

K-47. Comment: CARB has provided credit for DDGS, but finds little justification to provide even greater credits. (NRDC3)

Response: Several commenters have raised concerns with the 1:1 DGS to corn co-product credit provided in the ISOR and have cited either the Argonne work or results from their research to justify their request for a larger credit to DGS. It is with reference to this request for a larger credit that this commenter has concerns and accordingly indicates their position that the ISOR analysis has provided credit and there was no justification to provide additional credit. Staff position on this issue is that as indicated in responses to comments M-1 and M-2, the current 1:1 credit is a balanced one and appropriate using currently available information. In the future when the impact of all of the DGS from 15B gallons of corn ethanol is available from studies and research reports, appropriate refinements will be considered.

K-48. Comment: CARB has considered and incorporated a higher range of values for crop yields on converted lands. (NRDC3)

Response: The commenter supports efforts by staff to consider comments by industry and make refinements where appropriate when backed up by available data.

K-49. Comment: CARB has addressed concerns from the ethanol industry and incorporated many of their requests. (NRDC3)

Response: The commenter supports efforts by staff to consider comments by industry and make refinements where appropriate when backed up by available data.

K-50. Comment: Ohio applauds your leadership in promoting alternative fuels. Increasing America's energy resources and protecting national security by reducing our dependence on foreign oil, in addition to, continuing to grow our domestic renewable fuels industry are among the most important challenges facing our country. As corn growers we play an important role in reducing our dependence on foreign oil. However, we are deeply concerned about the trajectory of the current LCFS proposal in your state.

It is our understanding; the LCFS was originally intended to allow all eligible fuels to compete on a level, carbon-based playing field. There is widespread agreement in the scientific and research communities that biofuels produced from U.S. farms have significant benefits over petroleum and other fossil fuels like natural gas based on the "cradle to grave" carbon emissions associated with producing and using the fuel. For example, corn-based ethanol receives a 67 g/MJ. Advanced biofuels like cellulosic ethanol and renewable diesel have even better carbon scores. These numbers are considerably lower than California gasoline, which CA-GREET scores at 96 g/MJ.

To be clear, the CA-GREET model accounts for the carbon emissions directly attributable to the full lifecycle of the respective fuel. For biofuels the ARB analysis includes the application of fertilizer, and the land converted to produce biofuel feedstocks. For petroleum CA-GREET includes major upstream refinery emissions. In both cases transportation and combustion of the fuel is included. (OCGA)

Response: This comment is part of a longer letter which ultimately objects to the inclusion of land use change in the carbon intensity of biofuels. See also responses to Comments L-1 and L-75.

ARB identified indirect land use changes as a significant source of additional GHG emissions for some crop-based biofuels, and included the emissions associated with these changes in the carbon intensity values assigned to those fuels in the LCFS. The magnitude of this impact, however, has been questioned by some renewable fuel producers. Land use change is driven by multiple factors. Because the tools for estimating land use change are few and relatively new, some producers argue that land use change impacts should be excluded from carbon intensity values pending the development of better estimation techniques. Based on its work with university land use change researchers, however, ARB staff concluded that the land use impacts of crop-based biofuels are significant, and must be included in LCFS fuel carbon intensities. To exclude them would allow fuels with carbon intensities that are similar to gasoline and diesel fuel to function as low-carbon fuels under the LCFS. This would delay the development of truly low-carbon fuels, and jeopardize the achievement of a 10 percent reduction in fuel carbon intensity by 2020.

To help address indirect land use issues, the Board, at the April public hearing, directed staff to convene an expert workgroup to assist staff in refining and improving the land use and indirect effect analysis of transportation fuels and to return to the Board no later than January 1, 2011, with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. Staff is to coordinate this effort with similar efforts by the U.S. EPA, European Union, and other agencies pursuing a low carbon fuel standard.

K-51. Comment: Examining the stacked bars in Figure 8 showing the life-cycle component contributions to the totals reveals three points of note. First, industrial process energy – the thermal and electrical energy required to run the plant – is zero for a Brazilian plant because this energy is derived 100% from biomass. In contrast, industrial process energy amounts to over 10 MJ/liter for the US corn case. The second interesting point is that Brazilian sugarcane ethanol (when transported to US terminals) requires twice the energy for transportation to market as does US corn ethanol. Third, the animal feed co-products produced in US plants displace more than twice the fossil energy that exported grid electricity displaces in the case of Brazilian sugarcane ethanol. The stacked bar in the center of Figure 8 shows the same dry mill in Iowa, but using corn stover as fuel for the production of all required heat and power rather than using natural gas and grid electricity. In this case, the NREV of corn ethanol is comparable to Brazilian sugarcane ethanol. Brazilian sugarcane ethanol still has a greater NRER, 5.7 compared to 5.0, but the NREV of this corn ethanol case is greater at 23.66 MJ/l compared to 22.46 MJ/l for sugarcane ethanol. The reason that the corn ethanol NRER is lower than that of sugarcane ethanol, but the NREV is higher, is that the Iowa dry mill exports more energy (animal feed + ethanol) than its Brazilian counterpart. If the Iowa plant also exported electricity to the grid, its metrics would be even more favorable. (ICM3)

Response: ARB appreciates the comments and has considered the issues presented. The LCFS is based on a gCO₂e/MJ metric and does not use Net Renewable Energy Values. The staff analysis has considered the scenarios presented here but on a gCO₂/MJ basis. The credits for the animal feed coproducts have been accounted for in the ARB analysis (see also comment M-1 for co-product credit under Chapter M). Higher stover removal rates and subsequent use in generating process energy, may lead to decreased use of fossil fuel in ethanol production. However, increased stover removal rates may lead to increased fertilizer use or decreased yields which could offset the benefits of lower fossil fuel use. Further analysis of this practice and the associated effects on carbon intensity is required. In regards to electricity exports to the grid, if a facility is doing so, this could be incorporated in a fuel pathway analysis using Method 2A. See also the response to Comment K-40.

K-52. Comment: Figure 8 shows that the NREV value for Brazilian sugarcane ethanol is 22.46 MJ per liter of ethanol produced, while this value is 13.86 MJ/liter for corn ethanol produced at a modern dry-grind plant in Iowa. Brazilian ethanol

returns 62 percent more renewable energy than the dry-grind corn ethanol case. Additionally, the NREER values are 5.7 for Brazilian sugarcane ethanol and 1.9 for corn ethanol. In other words, for every unit of fossil energy consumed during the life-cycle production process, sugarcane and corn ethanol return 5.7 and 1.9 units of renewable energy, respectively. Clearly, Brazilian sugarcane ethanol has a large advantage over conventional corn ethanol from a net energy-balance perspective. (ICM3)

Response: ARB appreciates the comments and has considered the issues presented. However, the LCFS is based on a $\text{gCO}_2\text{e}/\text{MJ}$ metric and does not use Net Renewable Energy Values. Staff analyses present units for pathways on a gCO_2/MJ basis. See also the response to Comment K-51.

K-53. Comment: Net Life-Cycle Energy Value of Corn Ethanol versus Brazilian Sugarcane Ethanol The ICM/Econergy Model can be used to generate life-cycle fossil energy balances for ethanol produced from corn, milo, and wheat grown in a number of locations worldwide and using a number of different process-energy configurations. Additionally, the model contains a Brazilian sugarcane ethanol data set as a basis for comparison, since it is typically regarded as the most energy-efficient class of ethanol. To more effectively understand how these compare, some definitions should be introduced which provide metrics that can be used as a basis of comparison.

The Net Renewable Energy Ratio (NREER) is equal to the Fossil Energy In minus the Renewable Energy Out

The Net Renewable Energy Value (NREV) is equal to the Renewable Energy Out minus the Fossil Energy In

The Net Renewable Energy Ratio (NREER), often simply expressed as the Net Energy Ratio, is the sum of the energy outputs of the process divided by the energy inputs to the process. A value larger than one (1) indicates that the process produces more renewable energy than it consumes in fossil energy. The process, in this case, is an ethanol plant value chain including the upstream and downstream energy inputs necessary for the production of ethanol product. The produced energy ("Renewable Energy Out") includes the fuel energy replaced (gasoline-equivalent) and the energy embodied in the co-products displaced (i.e. distillers grains displacing corn grain and soybean meal in the case of corn ethanol). Brazilian sugarcane ethanol produces grid electricity as a co-product of making ethanol; the energy value of that electricity is a component of the "Renewable Energy Out" in that case. (ICM3)

Response: ARB appreciates the comments and has considered the issues presented. However, the LCFS is based on a $\text{gCO}_2\text{e}/\text{MJ}$ metric and does not use Net Renewable Energy Values or other metrics to measure the carbon intensity of fuels. Generally, with the same inputs and assumptions, models will likely generate similar results. See also

the responses to Comments K-51 and K-52.

K-54. Comment: The extraordinary amounts of investment capital deployed toward corn ethanol and soy biodiesel to date have built the structural members of this bridge to the future. While these plants have been built to convert commodity grains into biofuels, using fossil fuel-derived thermal energy and grid electricity, they have created the necessary biofuels infrastructure for the sustainable next-generation technologies to build upon. Furthermore, by installing combined heat and power (CHP) in these existing plants, by fuel-switching to biomass, and by installing other front-end technologies for converting cellulosic materials into biofuels, the life-cycle carbon emissions associated with fuels produced by our existing corn ethanol production capacity can be lowered dramatically – enough to be comparable with Brazilian sugarcane ethanol (see Figure 8 on page 23). In addition, corn ethanol production yields large amounts of protein to help feed a hungry world. (ICM3)

Response: We agree. The implementation of strategies discussed above have the potential for reducing the carbon intensity of corn ethanol and soy biodiesel. As mentioned in the response to Comment K-1, producers who incorporate emerging technological advances which reduce the lifecycle emissions may use Methods 2A and 2B to establish a pathway-specific carbon intensity value.

K-55. Comment: Combined heat and power systems (CHP, also known as cogeneration) generate electricity and useful thermal energy from the same fuel source in a single integrated system. The primary fuel feed stocks for CHP systems at ethanol plants include natural gas, coal, and biomass. (ILCORN)

Response: The Lookup Tables include pathways for corn ethanol that use natural gas, coal and biomass. As mentioned in the response to Comment K-1, producers who incorporate emerging technological advances which reduce the lifecycle emissions may use Methods 2A and 2B to establish a pathway-specific carbon intensity value.

K-56. Comment: Table 1 shows the projected changes to the primary energy feedstock and energy system configuration at ethanol plants over time. The base year (2007) numbers are taken from an industry survey conducted by Ethanol Producers Magazine (June 2006) adjusted by ethanol plant construction data provided by the Renewable Fuels Association and a study by Mueller and Cuttica (2006). For example, while currently 88% of ethanol plants utilize natural gas fired boiler technologies, the relative use of natural gas boiler technology is expected to decline by 2030 and natural gas boiler plants will constitute only 31% of the total stock of plants. The decline in natural gas boilers is expected to be due to increased use of biomass (combustion, gasification, integrated biogas systems) as well as increased deployment of natural gas CHP plants. (ILCORN)

Response: The projected changes in energy use and energy system configuration could change the CI associated with plants that implement these strategies. The

flexibility to do so is incorporated in the regulation. As mentioned in the response to Comment K-1, producers who incorporate emerging technological advances which reduce the lifecycle emissions may use Methods 2A and 2B to establish a pathway-specific carbon intensity value.

K-57. Comment: Calculations in the GREET model scale all crop inputs linearly to grain yield, with resulting intermediate parameters in British thermal units per bushel of grain (Btu/bu) and grams per bushel (g/bu); these units are presented as primary data in the CARB report, but they are actually integrative parameters that lack transparency as to the source of data. For example, the use of Btu/bu and grams/bu conflates reported energy and nutrient inputs per unit area for corn production (e.g. kg/ha, L/ha, kg/ha) with crop yield per unit area (Mg/ha), which results in spatial and temporal biases. Historically, nutrient use has also become more efficient and is not directly related to grain yield. Crop inputs per unit of grain yield vary substantially from state to state, with southern states requiring greater nutrient inputs per unit of grain produced, and western states requiring additional fossil fuel use for irrigation. As a result there is substantial spatial and temporal variability in net energy yields and GHG emissions for a given biofuel system that cannot be captured unless region- or state-specific values are used for inputs and outputs from the feedstock production system. Such regional analyses should use the most recent crop yields, nutrient input rates, and fossil fuel costs of energy and inputs used in all phases of the life cycle. Calculation of greenhouse gas emissions alone for LCFS implementation does not require estimation of criteria pollutant emissions VOC, and CO. Inclusion of these calculations in the core of the calculation structure of GREET may introduce inaccuracy and is non-essential for the calculations required for a LCFS. (UNE)

Response: At this time, the vast majority of ethanol is produced from corn, with the corn grown in the Midwest. If this changes, then new pathways for different crops and regions can be established through Method 2A and 2B. With regard to regional variability in crop inputs and grain yields, see response to Comment K-21.

K-58. Comment: A life cycle analysis of carbon intensity using the GREET model from Argonne National Laboratory using production estimates in this report shows the Global Warming Impact (GWI) from corn agriculture (on farm energy use for agricultural practices) could decline by 22 percent from 26,610 gCO₂eq/MMBtu (grams of CO₂ equivalent per million BTUs) in 2010 to 20,755 gCO₂eq/MMBtu by 2030. This is 25 percent below the current GREET default value of 27,469 gCO₂eq/MMBtu (ILCORN)

Response: As mentioned in the response to Comment K-1, producers who incorporate emerging technological advances which reduce the lifecycle emissions may use Methods 2A and 2B to establish pathway-specific carbon intensity values. In addition, when emerging technologies become industry-wide practice, the technological advancements can be integrated into existing fuel pathways. The Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014. These and

subsequent program reviews will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate. Section 95489(a) requires that these reviews consider “advances in fuels and production technologies.”

K-59. Comment: “The Potential Role for Corn Ethanol in Meeting the Energy Needs of the U.S. in 2016-2030” prepared for the Illinois Corn Marketing Board, 12/2007 by Ross Korves, Economic Policy analyst, ProExporter Network Addresses increase in availability of corn and decreasing Global Warming Impact in U.S. due to improved agricultural practices:

- Yield increase/improved fertilizer to reduce N₂O emissions
- Shift to no-till production: reduces CO₂ emissions (ILCORN)

Response: As mentioned in the response to Comment K-1, producers who incorporate emerging technological advances which reduce the lifecycle emissions may use Methods 2A and 2B to establish pathway-specific carbon intensity values. In addition, when emerging technologies become industry-wide practice, the technological advancements can be integrated into existing fuel pathways. The Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014. These and subsequent program reviews will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate. Section 95489(a) requires that these reviews consider “advances in fuels and production technologies.”

K-60. Comment: On May 10th, 2007 at the National Corn to Ethanol Research Center at SIU-Edwardsville, Alex Farrell met with the Illinois Corn Growers Association and members of the Illinois ethanol industry to discuss the biofuel implications of the proposed Low Carbon Fuel Standard. This presentation was based on Dr. Farrell’s vision and work supported by Argonne National Laboratory, University of California-Berkeley, and University of California-Davis. His numbers showed that Midwestern corn ethanol (including both coal and natural gas fired ethanol plants) would reduce greenhouse gas emissions 18 percent compared to gasoline. Natural gas powered ethanol plants, in isolation, realized about a 33 percent reduction. These numbers were based on 2001 agriculture input data and older ethanol production technologies and are thus conservative relative to current corn and ethanol production technologies. (ILCORN)

Comment: “A Low Carbon Fuel Standard for California,” Presentation by Dr. Alex Farrell, UCB, and Dr. Dan Sperling, UCD, May 7, 2007

Summary of report for ARB:

- AFCI for average Midwest corn ethanol of 76 gCO₂e/MJ; AFCI for gasoline 92 gCO₂e/MJ
- Mid-GHG value for corn feedstock, modern dry mill, nat. gas-fired, wet DGS, corn stover with AFCI = 58 g CO₂e/MJ

-Low GHG ethanol poplar, switchgrass, prairie grasses, cellulosic production
AFCI = 4 gCO₂e/M
(ILCORN)

Response: ARB used the analysis in Dr. Farrell's and Dr. Sperling's reports as the basis for the development of the LCFS. The results are different because the original analysis was upgraded to include additional information and data and to include the results of the analysis for land use change effect as documented in the ISOR. For some fuels such as the low GHG ethanol from poplar, grasses, and cellulosic feedstocks cited by the commenter, the analysis is not yet completed.

K-61. Comment: CA-GREET incorrectly assumes that the electricity generated from bagasse combustion is insufficient to create a surplus. Based on a correct understanding of the use of bagasse, the total GHG emissions for ethanol production should be reduced from 1.9 gCO₂/MJ to 1.1 gCO₂/MJ on average, with lower figures in the very near future. (UNICA)

Response: The CA-GREET analysis provides complete details of the energy and GHG emissions from sugarcane ethanol production. The 1.1 gCO₂/MJ cited here does not provide complete details for the basis of this calculation. ARB has developed a pathway which accounts for electricity produced from bagasse and it was incorporated into the regulation as part of the July 2009 modifications.

K-62. Comment: For instance, the paper points out that, "Sugarcane demonstrates particularly robust GHG savings through the use of bagasse as an energy source but potential still exists to improve boiler efficiency in many instances that would enable greater electricity production and export which would further improve GHG emissions." (VALENTE)

Response: ARB has developed a pathway which accounts for electricity produced from bagasse and it was incorporated into the regulation as part of the July 2009 modifications. As mentioned in the response to Comment K-1, producers who incorporate emerging technological advances which reduce the lifecycle emissions even further may use Methods 2A and 2B to establish pathway-specific carbon intensity values. In addition, when emerging technologies become industry-wide practice, the technological advancements can be integrated into existing fuel pathways. The Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014. These and subsequent program reviews will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate. Section 95489(a) requires that these reviews consider "advances in fuels and production technologies."

K-63. Comment: We also suggest that CARB staff look at the potential for a significant expansion of sugar cane acreage in Northeast Brazil where the greatest growth in sugar cane new acreage is occurring. This analysis should consider the potential that bagasse will be used for both production of ethanol

and 2nd generation biofuel with the remaining residues used for steam production in much more efficient boilers. Most boilers used by ethanol plants are not very efficient because of the low value of bagasse. Once technology to convert bagasse to biofuel exists at a full commercial level, ethanol plants are likely to install efficient boilers and convert bagasse to biofuel because of the doubling of income from the same feedstock. Our suggestion is that CARB and/or California Energy Commission staff work together to develop a guidance document for the sugar cane ethanol industry that suggests best practices for conversion of sugar cane to biofuel from an analysis of best available technology. This guide would immediately be used by the U.S. and global sugar cane industry to achieve biofuel production that leads to the best possible carbon benefits. (CO2STAR)

Response: ARB has developed a pathway which accounts for electricity produced from bagasse and it was incorporated into the regulation as part of the July 2009 modifications. As mentioned in the response to Comment K-1, producers who incorporate emerging technological advances which reduce the lifecycle emissions even further may use Methods 2A and 2B to establish pathway-specific carbon intensity values. In addition, when emerging technologies become industry-wide practice, the technological advancements can be integrated into existing fuel pathways. The Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014. These and subsequent program reviews will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate. Section 95489(a) requires that these reviews consider “advances in fuels and production technologies.”

K-64. Comment: One assumption of the UNICA study is that bagasse will continue to be used for power production in Brazil. While this could be true in Southern Brazil where there is a much higher contract price for electricity, we think this is unlikely in the Northeast where there is a much lower electric price and longer transport distance to move electricity to markets. Use of bagasse to produce fuel is a much more profitable option because of the higher value of fuel and the higher conversion rates of bagasse to fuel with some technologies. (CO2STAR)

Response: ARB has developed and included in the Lookup Table three different pathways for the production of sugarcane ethanol that reflect the differences in harvesting and electricity export. ARB realizes that some sugarcane ethanol may have actual carbon intensities which are less than the values listed in the look-up tables. For such situations and for processes that could convert bagasse to 2nd generation biofuels, there exist mechanisms (Methods 2A and 2B) in the LCFS to allow for producers to request a different evaluation for their specific pathways.

K-65. Comment: What we would like to stress in our comments to CARB on sugar cane ethanol from Brazil is how the growth of the sugar cane industry in Northeast states like Piaui and Maranhao (Maranhao has the fastest growth of sugar cane production in Brazil) is affecting the economics of sugar cane

conversion to alcohol and use of bagasse to produce electricity or fuel. Maranhao has variable yields on production of sugar cane in the state, with some areas achieving only 55-60 tons per hectare of cane, while other areas with high productivity are achieving yields of over 100 tons per hectare. This high photosynthetic productivity compares very favorably with the 15-30 tons/hectare possible with US switchgrass, the most commonly cited source of US cellulosic ethanol. In Sao Paulo state most of the sugar cane bagasse is burned to produce both steam for alcohol and sugar production and electricity for sale in the grid. In Northeast Brazil electricity has a much lower value because of the high concentration of hydroelectricity in the grid and distance to major growth markets for energy (Sao Paulo, Rio De Janeiro). This makes it less attractive to install the equipment needed for biomass electric sales to the grid, although this may change if Eletronorte is forced to pay higher tariffs for biomass electricity. The more attractive economic alternative is to use bagasse to produce steam for ethanol production and to produce 2nd generation biofuels. This will dramatically alter the life cycle carbon benefits of sugar cane. (CO2STAR)

Response: ARB has developed and included in the Lookup Table three different pathways for the production of sugarcane ethanol that reflect the differences in harvesting and electricity export. ARB realizes that some sugarcane ethanol may have actual carbon intensities which are less than the values listed in the look-up tables. For such situations and for processes that could convert bagasse to 2nd generation biofuels, there exist mechanisms (Methods 2A and 2B) in the LCFS to allow for producers to request a different evaluation for their specific pathways.

K-66. Comment: Mechanical harvesting generates a large amount of biomass that can be recovered and used to produce electricity through cogeneration (or in the future, additional ethanol production when cellulosic ethanol production processes are available). This recovery is not included in CA-GREET. (UNICA)

Response: ARB has developed and included in the Lookup Table three different pathways for the production of sugarcane ethanol that reflect the differences in harvesting and electricity export. ARB realizes that some sugarcane ethanol may have actual carbon intensities which are less than the values listed in the look-up tables. For such situations and for processes that could convert bagasse to 2nd generation biofuels, there exist mechanisms (Methods 2A and 2B) in the LCFS to allow for producers to propose a new carbon intensity for their specific pathways.

K-67. Comment: GREET-CA assumes that all sugarcane in Brazil is burned in the field prior to being manually harvested. A growing share of Brazil's sugarcane harvest (approximately 35 percent) is not burned and is mechanically harvested. (UNICA)

Response: Modifications to the rulemaking have resulted in three pathway documents for sugarcane ethanol and the resulting carbon intensity values are included in the Lookup Table. The two new pathways added to the Lookup Table account for situations where mechanical harvesting of cane and electricity export are adopted..

K-68. Comment: CARB should consider either of the following adjustments to the GREET-CA fuel pathways for sugarcane in order to reflect the variations in agricultural and industrial operations in Brazil's sugarcane industry, as well as to accurately credit carbon-reducing behavior:

Option One: GREET-CA could assume at least 70 percent of the sugarcane used for ethanol to be mechanically harvested and not burned in the field. The main sugarcane producing area of Brazil reached 50 percent mechanization in the last harvest and is required to have achieved at least 70 percent mechanization by 2010. When considering the whole of Brazil, about 35 percent of all sugarcane is harvested mechanically. The higher figure (from 35 percent to 70 percent proposed in this option) more accurately represents the actual source of the sugarcane ethanol that makes it to the United States.

Option Two: Alternative pathways could be developed for mechanically harvested, non-burned sugarcane ethanol and the adoption of more efficient cogeneration technologies described above. While more complex, such a method would have the benefit of not only accurately portraying current specific practices but also, proactively encouraging lower carbon intensity sugarcane biofuels production, which is the underlying public policy goal of the LCFS. In separate pathways, credit would be given to mills for non-burning of sugarcane in the field (i.e., avoided emissions), as well as the cogeneration surplus power displacing carbon intense fuels such as natural gas or heavy fuel oil used in marginal power generation in Brazil. (UNICA)

Response: Modifications to the rulemaking have resulted in three pathway documents for sugarcane ethanol and the resulting carbon intensity values are included in the Lookup Table. The two new pathways added to the Lookup Table account for situations where mechanical harvesting of cane and electricity export are adopted.

K-69. Comment: We believe a generic, single sugarcane pathway may not accurately incorporate these important changes in the way the sugarcane industry has and continues to evolve in Brazil. We note that merely creating separate pathways – one for “using bagasse for electricity production as a coproduct” and one for “using mechanized production of sugarcane,” as suggested in the Staff Report – will miss the mark as it presumes that these processes are mutually exclusive. The reality on the ground today is that mechanization and bagasse for electricity are occurring in significant levels and will only increase due to established regulations in Brazil. (UNICA)

Response: ARB has added two new sugarcane ethanol pathways to the Lookup Table. One of these pathways incorporates electricity export and the other incorporates both mechanical harvesting of cane and electricity export.

K-70. Comment: Under current regulations and agreements between the

environmental authorities and the sugarcane industry, nearly all the sugarcane in the State of São Paulo will be mechanically harvested by 2014. (UNICA)

Response: ARB has added two new sugarcane ethanol pathways to the Lookup Table. One of these pathways incorporates electricity export and the other incorporates both mechanical harvesting of cane and electricity export.

K-71. Comment: The uncertainties caused by the impact of harvest permits, coupled with the aforementioned legislative and regulatory changes, have led to a quicker than expected transition to all mechanized, unburned sugarcane harvest. According to Brazil's Sugarcane Research Center, which works with nearly all sugarcane producers, about 35 percent of all sugarcane in Brazil is already mechanically harvested, and nearly all of this is not burned in the field. In 2008, about half of the sugarcane fields in the state of Sao Paulo were mechanically harvested. And other states such as Goiás, Mato Grosso do Sul, and Paraná are also implementing mechanical harvest. In fact, the robust pace of mechanization was recently highlighted in a John Deere earnings release that states, "sales are being helped by [...] rising demand for sugarcane harvesting equipment." (UNICA).

Response: ARB has added two new sugarcane ethanol pathways to the Lookup Table. One of these pathways incorporates electricity export and the other incorporates both mechanical harvesting of cane and electricity export.

K-72. Comment: Any realistic evaluation of carbon emissions from sugarcane farming in Brazil must reflect the strict policies being implemented and action already taken that phase out of sugarcane burning, increase in mechanical harvest and cogeneration output. Without reasonable allocation of these various aspects, GREET CA cannot provide realistic carbon intensity values. In fact, the developers of the GREET model. (UNICA)

Response: ARB has added two new sugarcane ethanol pathways to the Lookup Table. One of these pathways incorporates electricity export and the other incorporates both mechanical harvesting of cane and electricity export.

K-73. Comment: Depending on various pathways and assumptions CARB decides to pursue, the values for sugarcane farming will vary. Considering the current levels of mechanical harvest (i.e., 35 percent of all cane) and a revised straw yield figure (14 percent of the cane), and 90 percent of actual burning in the burned area, total emissions from burning cane today should drop from 8.2 g CO₂/MJ to approximately 2.9 g CO₂/MJ. That should be the baseline for GREET-CA pathways. However, as noted elsewhere, we recommend that GREET-CA either considers an even lower figure to recognize that the sugarcane ethanol bound for California comes from areas that are already mechanized, or develop separate pathways to capture this carbon benefit. (UNICA)

Response: Pathway documents for sugarcane ethanol published in July 2009 do account for situations where mechanical harvesting of cane and using of bagasse for electricity production as a co-product is the adopted method. Data provided by the sugarcane industry were used for this analysis. It is expected that additional improvements will happen in the future and the regulation allows changes in the pathway analysis or creating new pathways by the use of Methods 2A and 2B. The Board has also directed staff to conduct mandatory program reviews in 2011 and 2014 at which time any refinements could be considered.

K-74. Comment: The single sugar cane pathway in the GREET CA model may not accurately incorporate the way the sugarcane industry has and continues to evolve in Brazil. Creating separate pathways – one for “using bagasse for electricity or fuel production and one for “using mechanized production of sugarcane,” as suggested in Table ES_6 of the Staff Report – will miss the mark as it presumes that these processes are mutually exclusive. The reality today is that mechanization and bagasse for electricity now and fuel in the future are occurring in significant levels and will only increase due to regulations and market demands for low carbon sustainable biofuel. Mechanical harvesting increases total biomass available from leaves and tops of cane stalks and this additional biomass will be transported to the mill for processing as multiple options exist for conversion of bagasse to electricity, fuel or chemicals. (CO2STAR)

Response: ARB has added two new sugarcane ethanol pathways to the Lookup Table. One of these pathways incorporates electricity export and the other incorporates both mechanical harvesting of cane and electricity export. For future processes that could convert bagasse to 2nd generation biofuels, there exist mechanisms (Methods 2A and 2B) in the LCFS to allow for producers to propose a new carbon intensity for their specific pathway.

K-75. Comment: To help justify this number we think it is important to highlight the reference made in the UNICA comments about the analysis by the OECD as follows: Ethanol from sugarcane is the pathway where the most consistent results were found. All studies agree on the fact that ethanol from sugar cane can allow greenhouse gas emission reduction of over 70 percent compared to conventional gasoline. The large majority of reviewed studies converge on an average improvement around 85 percent. Higher values (also beyond 100 percent) are possible due to credits for co-products (including electricity) in the sugar cane industry. This reflects the recent trend in Brazilian industry towards more integrated concepts combining the production of ethanol with other non-energy products and selling surplus electricity to the grid.” See page 44 of Economic Assessment of Biofuel Support Policies by Org. for Economic Cooperation and Development (2008), available online at <http://www.oecd.org/>. (CO2STAR)

Response: In the absence of the land use change affects the published CA-GREET

analysis shows that sugarcane ethanol GHG emissions for direct effects could provide for over 70 percent reduction compared to gasoline. Pathway documents for sugarcane ethanol published in July 2009 incorporate situations where mechanical harvesting of cane and using of bagasse for electricity production as a co-product is the adopted method. Here GHG reductions of over 85 percent are possible, again only when including direct impacts. When indirect impacts are considered, such reductions are lowered and the ISOR did provide for justification why indirect impacts have to be considered.

K-76. Comment: The difficulty in this discussion when looking at the current GREET CA model is that they assume that all energy from the burning of bagasse is used in the production of ethanol. This is not true in the case of current ethanol production as pointed out by the comments from UNICA and will certainly not be the case as there is increased utilization of surplus biomass for energy production. This includes the harvesting of straw in conjunction with sugar cane in the fields from the use of mechanical harvesters and the phase out of burning of sugar cane fields. It also results from the large amount of bagasse at a single location, making it an ideal resource for production of 2nd generation fuels (CO2STAR).

Response: ARB has added two new sugarcane ethanol pathways to the Lookup Table. One of these pathways incorporates electricity export and the other incorporates both mechanical harvesting of cane and electricity export. For future processes that could convert bagasse to 2nd generation biofuels, there exist mechanisms (Methods 2A and 2B) in the LCFS to allow for producers to propose a new carbon intensity for their specific pathway.

K-77. Comment: The mechanical harvesting (with no sugarcane field burning) yields a high amount of additional biomass (commonly referred to as “trash” and includes leaves and tops of cane stalks among other parts of the sugarcane plant). Some of this additional biomass is being recovered and transported to the mill for processing and much more is expected in the very near future. This biomass recovery process increases electricity production through cogeneration (or, in the future, additional ethanol production once cellulosic pathways are commercially viable). (UNICA)

Response: ARB has added two new sugarcane ethanol pathways to the Lookup Table. One of these pathways incorporates electricity export and the other incorporates both mechanical harvesting of cane and electricity export. For future processes that could convert bagasse to 2nd generation biofuels, there exist mechanisms (Methods 2A and 2B) in the LCFS to allow for producers to propose a new carbon intensity for their specific pathway.

K-78. Comment: I'm currently standing as opposed in the Low Carbon Fuel Standard. And I want to make sure that I don't -- nobody here probably opposes low carbon fuels, I certainly don't oppose the standard broadly defined. Our issue is with the

underlying data and the results. And we're happy to change our position later today if we can get a commitment on these two requests from the ARB. My first request is that the Board ensure that your green analysis uses accurate data. Though under current green modeling, sugarcane ethanol happens to be the lowest carbon intensity liquid fuel available under the look-up table right now, we believe it is actually significantly lower and the corrections need to be made. It should actually be something closer to less than 20 grams CO₂ per megajoule today. Our comments point out the basic errors that were made in the GREET analysis and that failed to capture the process of making sugarcane ethanol in Brazil. Perhaps more troubling to me is that the analysis ignored the improved low carbon practices ongoing in Brazil today. (BS)

Response: ARB has added two new sugarcane ethanol pathways to the Lookup Table. One of these pathways incorporates electricity export and the other incorporates both mechanical harvesting of cane and electricity export. ARB realizes that some sugarcane ethanol may have actual carbon intensities which are less than the values listed in the look-up tables. For such situations and for processes that could convert bagasse to 2nd generation biofuels, there exist mechanisms (Methods 2A and 2B) in the LCFS to allow for producers to propose a new carbon intensity for their specific pathways. ARB will continue to evaluate improved efficiencies to produce fuel and will make revisions when appropriate. The Board has directed staff to conduct mandatory program reviews in 2011 and 2014 at which time any refinements could be considered.

K-79. Comment: Total emissions from burning cane today should drop from 8.2 gCO₂/MJ to approximately 2.9 gCO₂/MJ. However, even a lower number should be considered to recognize that the sugarcane ethanol bound for California comes from areas that are already mechanized, or develop separate pathways to capture this carbon benefit. (UNICA)

Response: ARB has added two new sugarcane ethanol pathways to the Lookup Table. One of these pathways incorporates electricity export and the other incorporates both mechanical harvesting of cane and electricity export.

K-80. Comment: The advantage of the technology in understanding the potential from the use of biomass feedstock and fuel production potential of sugar cane is that it can use a wet feedstock to produce a chemical for conversion. Any GREET CA and even UNICA analysis of sugar cane bagasse assumes that it must be dried before use, leading to substantial energy use for drying. The use of wet feedstock leads to lower energy use to convert biomass to chemicals and use of methane suppressors means greenhouse gas emission impacts from methane are very low.

The impact if Terrabon technology if it is applied to a large percentage of bagasse produced in a region could be substantial. To help explain we use the following example:

Average Sugar Cane Production in Brazil 73 tons/hectare
Current percentage used for alcohol/sugar 15% or 11 tons/hectare of ethanol
Average percentage of water in sugar cane 40% or 29 tons of water for irrigation
Remaining bagasse in wet form 45% or 33 tons of bagasse
Conversion potential to mixed alcohol (55-60%) 55% of 33 tons or 18 ton of mixed alcohol or Conversion potential to bio-gasoline (50-55%) 50% of 33 tons or 16.5 tons of bio-gasoline. What this chart shows is that the utilization of bagasse for production of biofuel could lead to more than a doubling of biofuel production from the same amount of land developed. This will double the net amount of carbon sequestered from the land and provide a net carbon sequestration from sugar cane planting (life cycle carbon benefits of sugar cane to ethanol are up to 90% and could lead to a carbon benefit of up to a 180% range, although we anticipate the number will be lower due to deductions for land use change (or indirect LUC). (CO2STAR)

Response: The carbon intensity values generated using CA-GREET represent average industry-wide methods of farming, crop collection and transportation, fuel production, co-product generation, and distribution of fuel. ARB realizes that some sugarcane ethanol, because it is produced using more efficient processes, may have actual carbon intensities which are less than the values listed in the look-up tables. ARB has included a mechanism by which producers of such fuel may propose alternative carbon intensity values (Method 2A). Also, Staff will continue to monitor developments related to all stages of fuel production and will make carbon intensity adjustments when they are appropriate. Additionally, the Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014 which will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate.

K-81. Comment: For the sugarcane ethanol pathway, N₂O emission rates of 2 percent and 1.3 percent have been used interchangeably. The emission rate for N₂O is typically calculated as 1.3 percent of total nitrogen input. Global warming potential of N₂O is 300 times of that of CO₂. An error in the N₂O emission rate could cause a significant difference in the CI values. (CONOCO)

Response: The CA-GREET model uses a 1.3% N₂O emission rate and this has been appropriately used in the pathway analysis for sugarcane ethanol. This information is available from the pathway document published for sugarcane ethanol (September 2009 update) The Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014 which will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate.

K-82. Comment: However, industry practices continue to evolve, and we believe it is critical that CARB's analysis reflect the current state of the Brazilian sugarcane industry and avoid penalizing those players who have made investments in more efficient and sustainable methods of production since original GREET values

were established. (UNICA)

Response: The carbon intensity values generated using CA-GREET represent average industry-wide methods of farming , crop collection and transportation, fuel production, co-product generation, and distribution of fuel. ARB realizes that some sugarcane ethanol, because it is produced using more efficient processes, may have actual carbon intensities which are less than the values listed in the look-up tables. ARB has included a mechanism by which producers of such fuel may propose alternative carbon intensity values (Method 2A). Also, Staff will continue to monitor developments related to all stages of fuel production and will make carbon intensity adjustments when they are appropriate. Additionally, the Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014 which will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate.

K-83. Comment: The straw yield figures are above the norm for Brazil's sugarcane industry. Instead of 0.19 dry ton straw per ton of cane, you should use 0.14 dry ton straw per ton of cane. Based on our experience, it appears that the default values for straw yield are possibly based on Hawaiian, not Brazilian, sugarcane averages. (UNICA)

Response: The carbon intensity values generated using CA-GREET represent average industry-wide methods of farming , crop collection and transportation, fuel production, co-product generation, and distribution of fuel. There are values in literature for dry straw that support the values used in the CA-GREET model. When additional data becomes available, staff will review those and make appropriate refinements if necessary. Additionally, the Board approved LCFS requires mandatory regulatory reviews in 2011 and 2014 which will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when appropriate.

K-84. Comment: It appears that the energy required for transportation, and consequently the emissions assigned in GREET-CA, are higher than those obtained by our own ground-truthing measurements in Brazil. We believe that the discrepancy may well result from obsolete assumptions related to load performance of the vehicles during feedstock transportation. GREET-CA considers only 17 ton trucks, while a majority of mills already operate with trucks with two or three times greater loads. The specific energy consumption values for transportation from the field-to-mill vary according to the type of truck used and distance travelled. The mean distance travelled for field to mill is about 12 miles, as GREET-CA correctly assumes. Based on proportion of each type of truck used in field to mill transport from latest available data (i.e., 2004), we know that 8 percent of trucks were 15 ton single wagon, 25 percent were 28 ton double wagon, and 67 percent were 45 ton triple wagons. Therefore, based on this 2004 data, we calculate that the energy consumption of sugarcane transport from field to the mill to be approximately 20.4 ml/t-km, or about two thirds of the

consumption of a single wagon truck (i.e., 30.3 ml/t-km). In short, our recommendation would be to use 19,122 BTU/mmBTU instead of 25,722 BTU/mmBTU in Table 3.02.9 of the Staff Report. (UNICA)

Response: Although the data provided indicates that for some transport, larger trucks are used there are no data across the whole industry to ensure that all transport uses larger trucks. When data become available that all the cane is being transported using such trucks, appropriate refinements could be performed during the Board directed mandatory reviews in 2011 and 2014. The values in the pathways are currently generated using CA-GREET values for transport generated by Argonne, the original developer of the GREET model.

K-85. Comment: The energy values and associated emissions in the production of lime (CaCO_3) are said to be 0.6 g CO_2/MJ . However, lime produced in Brazil has significantly lower carbon intensity. As correctly noted in the Staff Report, Brazil's base load electricity (average mix) is currently approximately 83 percent hydroelectric, though the marginal expansion mix has been mostly natural gas. With this in mind, accurate input values for the production of lime in Brazil are 7 kWh electricity (with grid average mix) per ton of lime (not the mix of products found in some production plants outside Brazil, including calcium oxide) and 2.6 liters of diesel per ton of lime. Consequently, the GREET-CA values should be at most 0.11 g CO_2/MJ in the production. (UNICA)

Response: Lime is major feedstock for several operations in Brazil that include cement, steel, and farming. Staff was not able to independently verify total lime production in Brazil and total imports. Therefore, although lime produced in Brazil may have lower carbon intensity, imported lime may have higher carbon intensity. If imported lime is used for sugarcane operations the values may be higher. When such information becomes available, the staff will consider refinements to current estimates for the carbon intensity of lime production. The Board approved LCFS requires mandatory regulatory reviews in 2011 and 2014 which will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate.

K-86. Comment: GREET-CA carbon intensity values are far from the norm for current Brazilian agricultural practices. (UNICA)

Response: The carbon intensity values generated using CA-GREET represent average industry-wide methods of farming, crop collection and transportation, fuel production, co-product generation, and distribution of fuel. In response to Board approved changes in Resolution 09-31, two additional pathways were added to the average sugarcane ethanol pathway to reflect mechanized harvesting and the generation and export of co-generated electricity derived from burning bagasse. When additional data becomes available, staff will review these and make appropriate refinements if necessary. Also, the Board approved LCFS requires mandatory regulatory reviews in 2011 and 2014 which will provide opportunities to monitor developments related to all stages of fuel

production and make carbon intensity adjustments when they are appropriate.

K-87. Comment: As changes in field operations continue, energy efficiency improvements at mills already are adding to the surplus electricity provided to the national grid. In 2007, mills provided about 11,095 GWh, which corresponds to about 22.5 kWh per ton of raw sugarcane crushed. In 2008, the Ministry of Energy indicated that power generation increased to 15.768 GWh. This increase is a result of not only increase sugarcane production but, more importantly, new mills upgrading to high pressure steam cycle generators that produce at least 70 kWh per ton of cane with bagasse alone. Moreover, more efficient mills are entering into long term supply contracts with power distribution companies. For instance, the amounts already contracted for 2012 reach 45,180 GWh, which brings power generation to 65 kWh per ton of cane. There will be additional electricity incorporated into the grid by 2012, either through the scheduled government auctions or via open market sales, but those contracts have not yet been signed. Finally, looking ahead, when the additional sugarcane biomass (i.e., “trash”) is used for power production, the power generation values will increase to above 100 kWh per ton of cane within the decade (including bagasse and 40 percent of the straw previously burned in the field). (UNICA)

Comment: There are no credits for excess cogeneration electricity from sugarcane biomass. There is an inherent fallacy in any analysis of sugarcane that does not take into consideration the increasing surplus of cogeneration electricity produced at sugarcane mills in Brazil. Though GREET-CA recognizes that sugarcane bagasse is used to produce steam and electricity to power the processing, it does not consider that the mill is generating an increasing surplus of electricity, which is sold into the national grid displacing carbon intense sources of electricity. In other pathways (e.g., Farmed Tree Cellulosic), such credits are given and we see no reasonable basis to deny it within the GREET-CA for sugarcane. Failure to incorporate the anticipated growth in electricity cogeneration not only undermines one of the greatest environmental benefits of the sugarcane pathway, but also creates further discrepancies in the years ahead that could discourage carbon mitigation behavior. Based on the low end of the range of anticipated electricity sales to the grid (i.e. 45,180 GWh already contracted for 2012), a GHG emission reduction credit of 1.8 to 3.6 g CO₂/MJ should be granted under GREET-CA. Looking ahead, sugarcane mills operating with 70 kWh/t will achieve emission credits in the 10-20 g CO₂/MJ range, likely completely offsetting any emissions during production, processing, and transportation. IN fact, as the Organization for Economic Cooperation and Development (OECD) recently pointed out in a lengthy comparative analysis of biofuels, sugarcane ethanol may soon have negative emissions on a lifecycle basis. (UNICA)

Response: ARB has published pathways which account for electricity produced from bagasse. (http://www.arb.ca.gov/fuels/lcfs/072009lcfs_sugarcane_etoh.pdf). These pathways use data for additional electricity generated which was provided by UNICA

and which was also confirmed with the information used in the original Argonne model. For future improvements in energy use, as well as for conversion of trash to electricity, there exist mechanisms (Methods 2A and 2B) to allow producers to propose pathway-specific carbon intensity values.

K-88. Comment: Most Brazilian and international experts do not consider the volatile organic compounds and other pollutants in the GHG calculations, but do include the inputs of energy of equipments and construction. It appears to us that GREET CA does the very opposite. Reaching a consensus on these approaches would facilitate analyses and comparisons going forward. For simplicity, we have highlighted only the discrepancies that lead to fundamental shifts in model mechanisms of those that have a significant impact on the value of model outputs (UNICA)

Response: The ARB takes into account all pollutants that may contribute to GHG emissions. The CA-GREET model, approved by the Board, is a well recognized, peer reviewed, publicly available model, and stakeholders were made aware of the decision to use CA-GREET early in the LCFS development process. No other model can meet the same standards. It is common practice in lifecycle assessment of fuels to assume that each fuel source has similar and relatively minor emissions associated with equipment production and plant construction and therefore exclude these emissions from the scope of the assessment.

K-89. Comment: We have had a chance to review the UNICA comments provided to CARB in a letter dated April 16, 2009 and are in agreement with the text. We have worked extensively with the two non-profit organizations we are associated with in Brazil (Sustainable BioBrazil and Urban Bio-Alliance) and are very familiar with the issues related to development of feedstock and conversion of feedstock to ethanol, biodiesel and 2nd generation fuels in Brazil. Most of our comments will either reference their evaluations or suggest other areas they have left out. With regards to the core issue of life cycle carbon reductions of sugar cane, we agree that the 90 percent carbon life cycle reduction is a reasonable assessment of the real emission reductions and that this number will likely increase as a result of the requirements for use of mechanical harvesting, phase out of field burning in much of the Brazilian sugar cane industry and higher efficiency movement of cane to the plants with double or triple trailer trucks. We are also in agreement that electricity markets are strong in Sao Paulo and other Southern Brazilian states and that the new plants are getting the electricity contracts needed to justify a combined heat and power plant and more efficient burning of bagasse. (CO2STAR)

Response: ARB has added two additional sugarcane ethanol pathways to account for mechanized harvesting and combined heat and power energy production from bagasse. To account for pathways for ethanol which may have actual carbon intensities which are lower than the values listed in the look-up tables, the LCFS includes a mechanism by which producers of such fuel may propose alternative carbon intensity values (Methods

2A and 2B). In approving the staff recommendation as detailed in the ISOR, the Board recognized that availability of data from studies in the future may warrant refinements to the current analysis. The new information can be considered during two mandatory program reviews to be done in 2011 and 2014. With regard to truck use, see response to Comment K-84.

K-90. Comment: Existing plantations that still use manual harvesting in the state of São Paulo must obtain state-issued government permits for the pre-harvest sugarcane field burning. Environmental authorities have set strict contingencies upon which these permits can be suddenly revoked (e.g., if air humidity drops below 30 percent, cane burning restrictions are applied and if air humidity drops below 20 percent, all cane burning is suspended). This uncertainty has pushed many producers to mechanical harvesting to eliminate associated operational risk. (UNICA)

Response: Pathway documents for sugarcane ethanol published in July 2009 do account for situations where mechanical harvesting of cane and production of excess electricity is practiced.

K-91. Comment: Trends and literature confirm that credits will increase to offset other component emissions; new sugarcane ethanol pathways would allow for accurate credits to be given, particularly for incentivizing less carbon intense processes. (UNICA)

Response: ARB has added two new sugarcane ethanol pathways to the Lookup Table. One of these pathways incorporates electricity export and the other incorporates both mechanical harvesting of cane and electricity export. ARB realizes that some sugarcane ethanol may have actual carbon intensities which are less than the values listed in the look-up tables. For such situations, there exist mechanisms (Methods 2A and 2B) in the LCFS to allow for producers to propose a new carbon intensity for their specific pathways. Moreover, ARB will continue to evaluate improvements to fuel production methods and data sources and will make revisions to established pathways when appropriate. The Board has directed staff to conduct mandatory program reviews in 2011 and 2014 at which time any refinements could be considered.

K-92. Comment: The information for fuels derived from heavy crude oils, in specific the Canadian oil sands, needs to be updated. Based on the two recent LCA studies sponsored by Alberta Energy Research Institute, the default values for oil-sand derived fuels in the GREET model were over-simplified and less accurate compared to those estimated using actual field data. In addition, the studies showed CI values for oil sands-derived fuels varied with the technologies applied in oil sands production, upgrading and refining. The gap between conventional and heavy crude oil pathways does not appear to be as large as reflected in the CARB's analysis. (CONOCO)

Response: ARB has not performed an evaluation of Canadian oil sands since these

crude sources are not part of the 2006 California baseline crude oil mix. However, information provided by these independent studies may be used by ARB staff. When submitted to ARB by a regulated party, this information will be evaluated as part of the Method 2B process to determine the pathway specific carbon intensity of fuels derived from oil sands crude.

K-93. Comment: Based on these concerns and other consideration we would urge that the Board amend the LCFS regulation to assign the same carbon intensity to all mainstream crude oil fuel pathways from light to heavy crudes, including oil sand, rather crude from “the baseline crude mix”. Most of these crudes have similar lifecycle intensities with a narrow and continuous range. Most occurs at the end – at the burning phase of the cycle (CCG)

Response: The rationale for the LCFS regulation’s treatment of carbon intensity of CARBOB, gasoline and diesel fuel – including CARBOB, gasoline and diesel fuel derived from high carbon intensity crude oils not included in the 2006 California baseline crude mix – is set forth in Section II.B.3.

With regard to the carbon intensities of crude sources, we do not agree that all mainstream crude oil production methods have similar carbon intensities. Our calculations show that carbon intensities for mainstream crude oil production methods range from about 4 to more than 20 gCO₂e/MJ. Requiring all crude sources not part of the 2006 baseline mix to be evaluated individually will help to ensure that increased use of “high carbon intensity crude oil” production methods are accurately accounted for within the regulation. It will also provide greater incentive for these producers to reduce emissions through CCS or other methods.

The Board directed ARB staff to conduct comprehensive program reviews in 2011 and 2014 and return to the Board with regulatory changes if necessary. Section 95486 “Determination of Carbon Intensity Values” of the regulation will be a topic of this program review. See also responses to comments C-238 and C-239.

K-94. Comment: Furthermore, the LCFS methodology for baseline petroleum fuels should recognize and include the degradation of efficiency that is inevitable for these fuels as the more easily recoverable highest quality oil resources are consumed (MDSA)

Response: We agree that the carbon intensity of crude sources may change over time. Within the LCFS framework, crude sources not part of the 2006 California baseline crude mix are required to be evaluated individually as they enter the California market and be assigned an appropriate carbon intensity value. Furthermore, the Board has directed ARB staff to conduct comprehensive program reviews in both 2011 and 2014. The potential change in the carbon intensity of crudes included in the California baseline mix will be evaluated during the program reviews and addressed via regulatory change if deemed necessary.

K-95. Comment: For the compressed natural gas (CNG) pathway, the assumption that all natural gas would come from the U.S. seems inaccurate. Some natural gas and the marginal gas will come from liquefied natural gas (LNG). Evaluation of LNG should be included in the CNG pathway, or be established as a separate pathway. In our opinion, the carbon intensity for gathering, processing, treating, transmission, and distribution of U.S.-based natural gas appear to be optimistic. (CONOCO)

Response: Pathways for LNG, both from domestic and foreign sources of NG have been developed and provided in the LCFS lookup tables. The data for natural gas recovery, processing and transmission was from the GREET model which bases its inputs and values from information provided by the U. S. EPA, EIA and other sources. Also, ARB staff is developing regulations for California that will monitor production, processing, transmission and distribution of natural gas. Based on this analysis and updates at the federal and international level, appropriate refinements will be conducted in the future. This can be reviewed during the LCFS-mandated program reviews in 2011 and 2014 at which time, any modifications if appropriate may be considered.

K-96. Comment: To sum up, Clean Energy is asking for the following action items:

1. Include "LNG from domestic sources" and the blending of low carbon fuels with very low carbon fuels (i.e., CNG-biomethane, LNG-biomethane, and CNG-hydrogen blends) under the list of fuels that enjoy §95480 status upon final rule adoption.
2. Finalize the LNG pathway analysis promised and include domestic fuel scenarios that are reflective of the current LNG market for transportation; and,
3. Clarify to stakeholders that the use of a LCFS diesel fuel comparison in CARB's Draft LNG pathway analysis is only a projection and not a fuel that is actually available on the market today. Further, with the potential to blend very low carbon fuels with LNG, CARB should note that LNG as a fuel has the potential to further reduce its carbon intensity even in the near term. (CE1)

Response:

1. CNG and LNG biomethane from landfill gas have been published for review in July 2009. Based on comments received, updates were made available in September 2009. Staff has also published several LNG pathways (both from domestic and remote sources) in July 2009 and revised them in September 2009. As for blends as indicated by the commenter, these could be considered by the EO using existing pathways or by developing new ones using Methods 2A and 2B.
2. Staff has provided several LNG pathways as indicated above. The pathways include several for LNG derived from domestic sources (North American Natural Gas, Landfill Gas, and Dairy Digester Gas).
3. LNG produced domestically has the potential to be a low carbon fuel, particularly when derived from Landfill Gas and Dairy Digester Gas. Some of the other LNG

pathways could also provide lower carbon fuels depending on the specific pathway constraints (e.g., higher efficiency liquefaction). It is not certain if fuels identified in the LNG pathway are currently available in the market. The actual market availability will be driven by stakeholder involvement, financial investments for LNG production, penetration of LNG vehicles, etc.

K-97. Comment: Complete the LNG pathway analysis with realistic domestic LNG pathways as soon as feasible (CE1)

Response: Staff has published several LNG pathways (both domestic and remote sources) in July 2009 and revised them in September 2009 (LNG from North American Natural Gas, from South East Asia, from dairy digester gas, and from landfill gas). See also the response to Comment K-96.

K-98. Comment: First of all, the recommendation or the direction to finish the fuel pathway analysis for the liquefied natural gas for North American sources and from biogas. We very much appreciate. We're confident that when that's done, LNG from North American sources will be shown to be a compliant fuel. (CNGVC)

Response: Staff has published several LNG pathways, both domestic and remote sources in July 2009 and revised them in September 2009 (LNG from North American Natural Gas, from South East Asia, from dairy digester gas, and from landfill gas). See also the response to Comment K-96.

K-99. Comment: For the land fill gas (LFG) to compressed natural gas (CNG) pathway, some of the key assumptions are very optimistic. For example, the gas compressor efficiencies for compressing land fill gas to pipeline-grade natural gas was assumed 98% (a very optimistic assumption). (CONOCO)

Response: The assumption used was the same as the one used for regular natural gas. These were derived from work completed during the AB 1007 process by the California Energy Commission. Currently, work is in progress by the ARB to develop emission inventories for natural gas production and transmission. Based on the analysis from this study, appropriate refinements could be considered.

K-100. Comment: Other data appear to be obtained from a single resource or personal communications. In this case, sensitivity analysis may be useful to demonstrate the impact of critical parameters, such as the types of feedstock, the preprocessing requirements, the technologies available for generating LFG, the separation and compression efficiencies for natural gas, the flue gas treatment, etc. (CONOCO)

Response: The various inputs used in the Landfill Gas (LFG) pathway documents were based on CA-GREET's natural gas pathways, which are incorporated by reference in the regulation (section 95486 (b)(1)(G) and (K)). There is presently only one

installation in California known to staff that processes landfill gas to Compressed Natural Gas (CNG), and the pathway documents used information from that facility. For natural gas, all inputs and other parameters were from the North American Natural Gas (NANG) to CNG pathway that was published as part of the LCFS process. The inputs for this process were using data from sources such as the U.S. EPA, EIA, etc. Although the sources of the input parameters in the LFG pathway analysis were limited in number, they are well qualified to provide reliable data. Staff did not have to rely on questionable sources or personal judgment for any of the parameters used. As such, the performance of a sensitivity analysis would not contribute significantly to the accuracy of this pathway.

K-101. Comment: CWM argues that LFG to CNG document underestimates carbon intensity due to omit the landfill fugitive emissions. The LCFS may create an unearned subsidy for the landfilling of organic materials. Not only do these materials have far greater direct greenhouse gas benefits when they are managed outside of landfills, increased waste utilization outside landfills can also achieve other benefits such as soil health (from composting) and reduced financial risk to the state (from decreased landfill operations). It also asked the proposed landfill gas to fuel pathway be simply adopted at a later date, analogous to other fuel pathways still under development, after additional technical review and approval by the CARB Executive Officer. In the alternative, CWM would ask CARB staff to modify the existing fuel pathway. (WASTECT, SIERRACLB2)

Comment: Remove Incentives for Landfilling Organic Wastes. The landfill gas to Compressed Natural Gas pathway fails to account for fugitive landfill emissions and should be re-evaluated before being adopted as a fuel pathway within the LCFS. We ask that additional technical review and modifications to the landfill to fuels pathway be made before final adoption of the pathway. (SIERRACLB2)

Comment: The approach to fuels developed from waste lacks balance because it does not provide a pathway to produce fuel from processes involving alternatives to landfilling organic materials. To level the playing field, we ask that the Board give staff direction to develop a fuel pathway for fuels from dedicated anaerobic digesters. Development of the additional pathway will provide an alternative path for waste to be used, in a manner that reduces landfilling and that further supports the multiple environmental objectives of ARB and AB 32. (SIERRACLB3)

Comment: CWP asked ARB to develop the pathway from anaerobic digester. (CWP).

Comment: The landfill gas to CNG pathway has a particularly important flaw with regard to accounting for fugitive landfill emissions and should be re-

evaluated before being adopted as a fuel pathway within the LCFS.
(WATSEST1)

Comment: Landfill methane collection and destruction efficiencies are highly variable and difficult to measure – but likely highest in California with a well developed regulatory structure designed to minimize fugitive LFG emissions.
(WM1)

Comment: Others argue that if fugitive methane releases are a problem, that should be addressed directly by strengthening the emissions rules for landfills instead of “wasting” the energy value in captured landfill gas. This claim is dubious in that those raising it are the same one’s fiercely opposing efforts to do something elsewhere. But, in any event, the larger point is that the same landfill geometry described earlier has defied efforts to reliably measure emission levels, without which strict regulation is impossible, as does the fact that much of the emissions occur when the owner is long gone. There are some modest salutary prescriptive measures that could be adopted, such as closer well spacing and quicker installation of final covers. However, in addition to the fact that the staff has peremptorily refused to consider prescriptive standards, their imposition, which would keep the site dry for the foreseeable future, will also retard methane generation and make energy recovery impractical. For the foregoing reasons, we ask that the landfill section be removed from these standards. After the staff properly accounts for fugitive landfill gas impacts, landfills can be brought back on the table with the several other items slated to be treated outside the rule.
(CCWI)

Comment: Waste management urges ARB to:

- continue to rely on your other (and more appropriate) regulatory control measures to ensure reductions in landfill gas emissions;
- maintain its current approach in calculating carbon intensity – an approach that will incentivize capital investments in clean fuel production and in the improved collection of methane from landfills. (WM1)

Comment: The control of landfill GHG emissions must be a carefully crafted to include both regulations to control landfill fugitive emissions and incentives to maximize the beneficial capture and use of otherwise wasted and flared LFG energy. (WM1)

Comment: Fugitive landfill emissions should not be considered when determining the carbon intensity of fuels derived from LFG that would have otherwise been combusted in a flare. Including fugitive emissions will not result in a more beneficial outcome. (WM1)

Response: ARB recognizes the issue of fugitive emissions from landfills. The LCFS covers the estimates of emissions from the collection point of the gas collection system. The fugitive methane emissions prior to the gas-system collection point are controlled

by California Integrated Waste Management Board regulations that currently require control of 85 percent of fugitive emissions in the large landfill and ARB, under AB 32 established a landfill methane control measure. This accounts for the fugitive methane emissions prior the collection point of the gas system. As a result, for the LCFS fuel pathway of landfill gas (LFG) to compressed natural gas (CNG) or Liquefied Natural Gas (LNG), we estimate the GHG emissions from the collection point of LFG to the end user as final fuel.

The Dairy Digester Biogas (one of the types of anaerobic digesters) pathway to CNG and LNG has been included in the LCFS. Other pathways using anaerobic digesters can be established using Method 2A and 2B.

K-102. Comment: The Waste Management has different opinion: “Fugitive landfill emissions should not be considered when determining the carbon intensity of fuels derived from LFG that would have otherwise been combusted in a flare. Including fugitive emissions will not result in a more beneficial outcome.” “Encouraging the development of LFG to low carbon fuels is not in conflict with policies to divert organic waste from landfills. “ Landfills can effectively produce low carbon LNG or CNG from landfill gas without compromising landfill methane collection and destruction efficiency, either by supplementing the well field or by including nitrogen removal technology in the process. With respect to recirculating liquids, managing liquids in a landfill is strictly controlled by state and federal regulations. When allowed under these regulations, operations to optimize landfill moisture content can be used to manage and optimize the rate of decomposition to increase useable landfill capacity, reduce post closure maintenance, and reduce contaminant levels in the landfill leak rate. The addition of liquids can also optimize gas production that can support a greater degree of energy recovery over shorter time window to optimize the viability of such a project. Such operations may increase LFG production and necessitate additional flare capacity, or increased energy or low carbon fuel production. However, such moisture optimizing operations are rarely performed for the primary purpose of justifying a new landfill energy or fuel plant or for supporting an existing landfill energy or fuel plant. There is absolutely no basis for assuming that when moisture is properly managed in a landfill, the incremental increase in LFG cannot be successfully collected and managed by the gas collection system. In fact, it is exactly this type of landfill technology that can reduce the need to site new landfills by taking maximum advantage of existing permitted landfill capacity. All of these objectives can be balanced so that landfills with energy recovery and/or liquids recirculation do not have any increase in fugitive methane emissions.” (WM)

Comment: Managing a solid waste landfill to enhance energy recovery does not increase fugitive landfill gas emissions. (WM1)

Comment: Maximizing the capture and beneficial use of LFG to produce a fuel is not in conflict with the diversion of waste to alternative technologies to produce fuels, energy and compost. (WM1)

Response: See the response to Comment K-101 and K-103 on the issue of fugitive emissions. Landfill processing technologies are not covered by the LCFS. As for production of fuel from waste, the LCFS incentivizes the development of novel technologies to convert waste to transportation fuels. Accordingly several pathways that include such feedstocks have been published and additional pathways may be published in the future.

K-103. Comment: The defense for ignoring landfills' lifetime emissions essentially rests upon the unsupported and incorrect claim that the generation and emissions of methane from landfills are fixed. Therefore, the claim continues, adding more subsidies for landfilling through the LCFS program will not methane emissions, but rather would only encourage more of the latent energy value in landfill gas to be utilized as an alternative for transportation fuels. This recitation in no way conforms with the facts. For one thing, of all the alternatives for managing our organic discards, only landfilling generates significant uncontrolled methane as a by-product of their decomposition. Over 100 programs in North America, including 42 in California, have demonstrated the practicality of diverting as much as 70% of the organic stream away from landfills. Burying garbage is the only management option that generates substantial volumes of uncontrolled methane, a significant part of which escapes. With methane's 25× to 72× potency, there is no conceivable set of assumptions which avoided carbon dioxide emissions from LFG to CNG would exceed the warming impact from the methane that escapes. Since none of the organics processing alternatives produce significant uncontrolled volumes of methane in the first instance, diversion is always a substantially more effective strategy to reduce net GHGs than recovering energy from landfill gas. Yet the effect of undercounting LFG to CNGs carbon intensity will be to subsidize disposal and, thereby, increase the hurdle for those same non-methane generating alternatives to be economically justified. A few cities may chose to divert their organics for environmental purposes even when landfilling is cheap. But, most will be guided by the comparative economics. Staff's factually unsupported position will lead to more net GHG emissions than would occur absent the LCFS program. Moreover, for another, making matters worse, landfills operated for energy recovery are not managed the same as traditional sites, because the latter are too dry to produce gas with enough high Btu methane to be economically useful. By delaying installation of the final cover and other strategies, moisture is increased, boosting methane concentrations and overall gas production, but at the expense of degraded collection efficiency. This generally unknown fact among the public is widely acknowledged by the industry: Furthermore, a site with a collection system that is used solely for energy recovery is usually not capable of achieving as high a collection efficiency as compared to one that is compliant with NSPS regulations." (Solid Waste Industry for Climate Solutions, *Current MSW Industry*

Position and State-of-the-Practice on LFG Collection Efficiency, Methane Oxidation, and Carbon Sequestration in Landfills (Jul 2007), at 10.) •#•

“[Overpulling] and other related strategies can lessen surface emission (to extents somewhat difficult to measure and quantify) and achieve better gas recovery and quality (more easily quantified). However they can reach points of diminishing returns. In the case of increasing extraction or “overpull” relative to generation, air entrainment inhibits methane generation. And with overpull, dilution of landfill gas with air can limit certain energy uses.” (Don Augenstein et. al., *Improving Landfill Methane Recovery – Recent Evaluations and Large Scale Tests*, Presentation to Methane to Markets Partnership Expos (2007), at p. 3.)-4-•#• Gas recovery efficiency is maximized [when] header pipeline methane [is] at 40 to 50% (rather than 50 to 60 percent, suggesting tuning wells for maximum recovery.” (SWANA, *Comparison of Models for Predicting Landfill Methane Recovery* (1998), at p. 2-3. This is why further claims in defense of the staff report in connection to existing wastes are also not valid. They argue that for waste-in-place, the non-methane producing alternatives do not exist, and for that reason, the comparison here is between energy recovery and flaring the gas. Of course, the proposed rule does not restrict LFG to CNG’s carbon footprint to gas only from new wastes, and therefore the defense is irrelevant to this case. But, even if the had restricted its reach to gas from previously buried trash, the comparison must also include the foregoing changes in operations that increase uncontrolled releases of methane. While the options are constrained for waste-in-place, as noted, those who operate energy producing landfills’ modify their practices in order to optimize revenues by creating substantially more methane, proportionately more of which escapes. In the case of new wastes, there are no realistic set of assumptions in which the warming influences from the potent methane that escapes would not overwhelm the benefits in avoided CO₂ emissions. Here there may be some assumptions within the zone of reasonableness that might alter the answer. But, the point being is that, like demand for oil, the amount of methane released from landfills is a variable as a function of, among other things, landfill pricing, which will be affected by the staff’s proposed carbon accounting. (CCWI)

Comment: Furthermore, methane is an especially potent greenhouse gas with 25 times the warming impacts of carbon dioxide (CO₂), and in the short term that we confront a tipping point, more than 72 times CO₂. Thus, the lifetime generation of methane from just one year’s output of wastes has an impact equivalent to 165 million to 475 million tons of carbon dioxide, depending upon whether the long term or short term issues are under consideration. Because a modern landfill exceeds the volume of 100 to 200 football stadiums sprawled across hundreds of acres, and because most gases are generated before and after functioning gas collection systems are in place, no one actually knows how much of that 165 million to 475 million tons of CO₂E escapes into the atmosphere. The U.S. Environmental Protection Agency (US EPA) assumes 75% is collected, EPA-Region 9 assumes a 30% capture rate, and the

International Panel on Climate Change (IPCC) states that capture “may be as low as 20%.” The wide difference in assumptions lies in the use of dramatically different definitions. US EPA defines capture rates based upon what they guess the best systems should achieve during the limited time gas collection is functioning. The IPCC states that if instead performance is defined as the average, not best, and over its entire lifetime, not just best-in-time, the lower value is indicated. Thus, long term landfill uncontrolled GHG emissions from each year’s garbage telescoped back to today range from approximately 41 million to 132 million tons, and in the short term, from 119 million to 380 million tons, depending upon the definitions used.

Yet, the staff position is that these hundreds of millions of tons of carbon dioxide equivalent emissions from the annual burden of trash in California should be ignored – just like corn ethanol proponents contend that its impact on presently untillable lands should not be considered – to wit: “[I]t is assumed that no L[and] F[ill] G[as] leaks during the recovery process.” (Detailed California-Modified GREET Pathway for Compressed Natural Gas from Landfill Gas, at p. 9). The GREET model used for analyzing transportation fuel alternatives does not support such an assumption. Rather, staff acknowledges that the “[l]andfill gas to CNG pathway is not available in the original Argonne GREET model but has been coded into the CA-GREET model” with the staff’s assumption that “no LFG leaks.” (Modified GREET, at pp. 2 and 9.) That assumption is not in accord with the principles Argonne used to model a life-cycle analysis, i.e. one that encompasses all up and down stream impacts over the relevant time period: “Designed to analyze energy and emission effects of new transportation technologies and the use of alternative transportation fuels, GREET evaluates technologies on the basis of what is commonly referred to as the ‘*total energy cycle*.’” (emphasis added). The agency’s modified model needs to be corrected to analyze the life cycle impacts of landfill gas to CNG, including the pathways accounting for very large methane emissions. Otherwise, major sources of greenhouse gases, whose potency may overwhelm claimed benefits, will be ignored. (CCWI)

Comment: Landfills normally release major volumes of methane (CH₄) into the atmosphere, and, equally important, when landfills are modified to optimize energy production, substantial additional volumes of methane are created, of which proportionately more escapes. Over the prolonged period that gas generation from municipal solid waste (MSW) extends, each ton is anticipated to produce approximately 315 pounds of methane. For California’s annual 42.2 million tons of MSW, that normally totals 6.6 million tons of CH₄ associated with each year’s discards. When sites are converted to energy production, the near term production of methane concentrations in landfill gas is increased by approximately one-third, and, to an unknown degree, gas collection efficiency is degraded and some future gas generation is shifted to the present. (CCWI)

Response: The regulations currently in place and being considered for landfills in California, will mandate the percentage collection of fugitives that has to be accomplished to comply with regulations in place. This is based on the total emissions generated annually. As for re-direction of waste as is being indicated as likely to happen, we do not believe that this is a likely scenario. The various estimates being presented above and the concerns over methane emission increases are not under the LCFS regulatory purview. They are likely to be handled by measures being implemented under AB32 (the Climate Action Solutions Act in California) and steps being implemented by the Integrated Waste Management Board, a sister agency to the Air Resources Board. As for lowering GHG emissions, the LFG pathway only provides credit for the landfill gas that is actually drawn from the collection system already in place at a landfill location based on their mandated requirements to have such systems in place. The analysis therefore using CA-GREET is a robust one and actually considers the lifecycle analysis using a relevant system boundary for landfill gas to CNG (and LNG).

K-104. Comment: 1. CO₂ Emissions from Plug-In Hybrid Vehicles (PHEVs) and Electric Vehicles. It is extremely important that CO₂ produced in the course of producing electricity to charge plug-in hybrid or electric only vehicles be properly accounted for in Clean Air Act mandates.

2. Uniform Calculations for Advanced Biofuels CO₂ Emissions.

With the potential of CO₂ emission or fuel economy waivers being granted to California and the New England/Mid Atlantic States, there is the possibility of at least three different standards.

3. All energy lost (approximately 60 percent) in the generation and transmission of electricity used to recharge electric and plug-in hybrids must be accounted for. Since most of this is from non-renewable fuels, significant GHG emissions must not be missed.

4. The energy and GHGs used to extract and concentrate uranium to electrical production levels and the energy/GHGs and costs required for the secured long-term storage of spent fuel must be accounted for. In addition, the national security costs of relying on.

5. The environmental damage caused by petroleum extraction in sensitive ecosystems, including the Arctic and tar sand basins, and the energy and GHGs produced to remediate them must be accounted for.

6. The energy and GHGs used to produce batteries for hybrids and electric cars (above that used to produce baseline gasoline vehicles) must be accounted for. In addition, the energy and GHGs required to dispose of batteries in an environmentally neutral manner must be accounted for as well.

7. The production conditions of the base case gasoline fuel must include sources that would be used post 2012 in order to provide a comparable case to advanced biofuels that would begin to reach the market by that date. This would mean including the costs and GHG effects of using tar sand, deep ocean, and Arctic petroleum.

8. The calculation of GHG effects of biofuels must include provisions for future GHG reductions. These include; nutrient input reductions, reductions in use of food crops, reductions in non-renewable fuel use for farming and processing, innovations in biomass. (ABUSA)

Response: Currently the CA-GREET model as it is used by ARB includes the WTW electricity generation from a variety of sources according to the CA average electricity portfolio. Emissions associated with electricity production do account for generation and transmission losses. For nuclear power, emissions accounting also includes the extraction of uranium and production of fuel but does not include storage of wastes.. Also, battery production and disposal is not accounted for as vehicle manufacturing is not considered within the lifecycle assessment boundaries for electricity used as an alternative fuel..

With regards to the use of petroleum, the CA-GREET accounts for the production of transportation, refining, and combustion of petroleum fuels as they are currently supplied. The rationale for the LCFS regulation's treatment of carbon intensity of CARBOB, gasoline and diesel fuel – including CARBOB, gasoline and diesel fuel derived from high carbon intensity crude oils not included in the 2006 California baseline crude mix – is set forth in Section II.B.3. The Board approved the lifecycle evaluation of crude oil sources included in the 2006 California baseline crude mix. As new crude oil sources enter the California market, pathway lifecycle assessments submitted by regulated parties using the method 2B process will be evaluated and appropriate carbon intensity values will be assigned to fuels derived from these crude sources. This review process will be conducted in an open and transparent manner.

In regards to the comment for including provisions for future GHG reductions, the regulation requires future periodic reviews to take into account improvements in fuel production and technology.

And last, regarding the comment on uniform CO₂ methodologies with other jurisdictions, the ARB is discussing these issues with other agencies that are in the process of developing LCFS regulations.

K-105. Comment: We urge CARB to review and reconsider the following key items in the proposed LCFS regulation:

- Treatment of perennial grasses, specifically switchgrass
- Yields and values of co-products, in particular Distillers Grains
- Impact of agricultural practices and productivity on carbon intensity calculations

- Technology timelines and economic assumptions
- Definition and inclusion of indirect effects. (DUPONT1)

Response: The items identified as needing to be reviewed and reconsidered were addressed extensively during the public hearing held in April 2009 by the Board. The Board, in Resolution 09-31, recognized that new information on such topics should always be considered. It should be noted that the treatment of perennial grasses, especially switchgrass, was not decided at the Board hearing. A pathway for perennial grass has not been established, in large part because no commercial process has been developed for conversion of the perennially grasses into a motor vehicle fuel. Once available, it can be incorporated using Method 2B. The consideration of co-products in particular DGS was subject to extensive evaluation in the ISOR and will be reconsidered during the mandatory program reviews in 2011 and 2014. As information on widespread agricultural practices and productivity changes become available, they too will be considered in the mandatory program reviews. If warranted, pathways will be updated to reflect new yield data averaged over 3 years to minimize weather influences. Changes in practices will be evaluated for permanence and longevity. Concerning technology and economic assumptions, these are clearly addressed in the ISOR and will be further addressed in the mandatory reviews as new data becomes available. Finally, as detailed in Resolution 09-31, the Board directed staff to convene an Expert Workgroup to review land use change modeling, including indirect effects and develop recommendations on how to refine the modeling.

K-106. Comment: There are multiple pathways listed for corn ethanol alone in Table IV-1. The corn ethanol pathway report details the Midwest average model, but does not describe the basis for the other models. While the CARB proposal states that the CA-GREET model uses farming and agricultural chemical use data from the USDA, no reference is listed and the information is not provided in the pathway document.⁴ In the case of land conversion effects, the calculations described on page IV-21 assume that 90% of the above-ground carbon sequestered in plants is emitted as it is burned to clear the land for agriculture. Grassland and pasture do not contain as much aboveground carbon compared to forest, and wood from forests is a valuable building material that would likely be at least partially harvested prior to burning. It is unlikely that the default pathways can address the multiplicity of feedstocks, farming practices, technologies, or potential external market factors. Given the requirements outlined for alternate pathway approval, fuller transparency and clarification of the CA-GREET model is required in order to ensure consistent modeling and evaluations across all fuel types. (DUPONT1)

Response: The CA-GREET model is derived from the GREET model developed by the Argonne National Laboratory with the differences being those necessary to adapt the model to be more specific for California. These changes would be such things as adjusting transportation distances to bring Midwest corn ethanol to California. The references for feedstocks, farming practices, etc., stay the same. The Board in Resolution 09-31, directed staff to prepare a guidance document to assist applicants in

preparing information to support establishing a new sub pathway or pathway using Methods 2A and 2B. This document has been drafted and made available for comment. While GREET has been widely used and described, a draft guidance document is available and staff encourages applicants to meet with staff early in the process to minimize the time and effort to develop proposals under Methods 2A and 2B. Also, see response to Comment L-31.

K-107. Comment: In addition to the impact of driving up global demand for commodity crops, several studies, including Crutzen and Howard et al. shows that nitrous oxide emission from heavy fertilizer application contributes to global warming far more than previously appreciated. Also, the fuel-intensive organization of the agriculture industry ensures that every step of the process entails significant energy consumption, resulting in a large amount of “embedded emissions” in the final ethanol or other agro-fuels product. The processes of harvesting, processing, transportation, and refining are extremely fuel-intensive, and often involve coal-fired electricity or direct emissions of extremely potent greenhouse gases such as methane or nitrous oxide. (STEILZ)

Response: The items identified by the commenter as being important for determining the CI of biofuels are in CA-GREET. They must be quantified when any new pathways or subpathways are proposed and established through Methods 2A and 2B.

K-108. Comment: NRDC, Sierra and some other well-meaning environmental organizations, are opposing combustion with energy recovery (waste-to-energy or WTE) and landfill gas (LFG) recovery on the grounds that such support will impede recycling or composting. There are no anaerobic digestion plants in the U.S. The U.S. source-separated organic wastes are either composted or used beneficially as Alternative Daily Cover in landfills. The U.S. is the world's largest landfiller: It landfills about 25 percent of the global total. In consideration of the above factors, the Earth Engineering Center of Columbia University applauds CARB's efforts to increase LFG recovery in California, as well as any other state or federal measure that will help reduce the environmental impacts of waste management industry. (Columbia)

Response: ARB appreciates the supportive comments and is considering the points raised.

CA-GREET Not Current, LUC Model Not Valid

K-109. Comment: A recently released peer reviewed publication in the Journal of Industrial Ecology titled Improvements in Life Cycle Energy Efficiency and Greenhouse Gas Emissions of Corn-Ethanol has shown that corn based ethanol reduces direct greenhouse gas (GHG) emissions by 48 percent – 59 percent as compared to gasoline. But CA LCFS look-up tables don't reflect this peer reviewed information.

Regarding the large difference between the California dry mill, wet DGS pathway and the Midwest dry mill, wet DGS pathway: I have not been able to locate the pathway for California ethanol and thus not wanting to assume why the large difference. I believe you have not been completely open and upfront on disclosing of information.

The adoption and usage of data of current production practices, input efficiencies and yield: According to various National Agriculture Statistics Service and Economic Research Service reports, yield is increasing at a faster pace than previous trend lines and we have increased our fertilizer use efficiency greatly over the past thirty years. But the CA-GREET model does not incorporate all of these advances and efficiencies.

The use of current feeding rates of co-products and their adjusted credits: Dr Michael Wang, et al in September, 2008 released up to date feeding and displacement ratios for distiller's grains. In the update, it indicates that for each pound of distiller's grains that is placed in a ration, it replaces 1.28 pounds of conventional corn and soy-based feed. This is greater than the current ratio that CARB is using and the new data should be incorporated into the model. (NCB, MCGA)

Response: With regard to the publication in Journal of Industrial Ecology see responses to Comments K-6 and K-20.

With regard to the disclosure of information in the corn ethanol pathway document see response to Comment K-25.

With regard to improvements in farm practices and yields see response to Comment K-4.

With regard to co-product credit see response to Comment M-1.

K-110. Comment: There are a number of new technologies, some of which will be summarized in this review, that contribute significantly to the energy efficiency of dry grind ethanol production. Unfortunately, CARB is using technologies that are nearly a decade old, thus ignoring modern near term technologies. The energy efficiency of fuel-ethanol plants that use corn as the source of fermentable sugars has increased dramatically over the past 15 years, and new technologies are available that can further decrease the requirements for fossil energy. For example, energy requirements of 40,000 Btu/gal or 1.4kW/hr/gal were good. Today ICM (major manufacturer ethanol plant) guarantees 30,000 Btu/gal and 0.75 kW-hr/gal. Two technologies that can reduce the fossil-fuel requirements for process heating in the corn-ethanol process are dry fractionation and anaerobic digestion. Additional efficiencies could be realized by greater use of established technologies, such as combined heat and power system, etc. Dry fractionation is a front-end (i.e., before fermentation) process that can increase the variety of products produced by a fuel-ethanol plant, improve the nutritional quality of the

animal-feed co products, and reduce the energy required for drying those co-products. Anaerobic digestion is back-end (i.e., after distillation) process that can be used to convert the non-fermentable components of the corn kernel into methane gas, which can be used as a direct replacement for natural gas to fuel existing boilers and dryers. These and other opportunities for improving the energy balance and reducing the carbon footprint of corn-based ethanol are described in a recent report by Mueller and Copenhaver (2009). Because the fossil-energy requirements for production of ethanol from corn can be reduced Because the fossil-energy requirements for production of ethanol from corn can be dramatically reduced by adoption of many of the technologies described in this report, and almost completely eliminated if several combinations of technologies are adopted, the actual greenhouse gas emissions of specific facilities should be considered in the designation of advanced biofuels. There is no scientific justification for determining whether ethanol qualifies as an advanced biofuel based only on the feedstock used in its production without also considering the technologies were used to convert the feedstock to the biofuel. (NCERC2)

Response: The processes that are being discussed above are not applied industry-wide and some are still in the process of being evaluated. We are aware of the work done by Mueller and Copenhaver, where they are looking for potential improvements in ethanol production. The ARB analysis for corn ethanol is based on the calculations of the latest GREET model updated in September 2008 by Argonne and modified by ARB. The Board-approved LCFS provides a mechanism to develop new pathways through Methods 2A and 2B. These methods will allow producers to propose pathway specific carbon intensity values. Additionally, the Board-approved LCFS requires mandatory regulatory reviews in 2011 and 2014 which will provide opportunities to consider developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate.

K-111. Comment: Most Brazilian and international experts do not consider the volatile organic compounds and other pollutants in the GHG calculations, but do include the inputs of energy of equipments and construction. It appears to us that GREET-CA does the very opposite:

- Straw Yield: 0.14 instead of 0.19 dry tonne/tonne of cane
- Lime production CaCO_3 is $0.6\text{gCO}_2/\text{MJ}$ in GREET but it should be $0.11\text{g}/\text{MJ}$ based on Brazilian lime production energy use
- Sugarcane truck load capacity should be average 34 ton not 17 tons
- Mechanical Harvesting
- Ethanol production should be 1.1, not $1.9\text{ g}/\text{MJ}$ based on correct use of bagasse
- Should adopt verifiable mechanism that ensure best carbon mitigation practices are rewarded
- Need to reflect current practices in the Brazilian sugarcane industry and avoid penalizing those who made investments.
- Need to develop addition pathway for using bagasse as burning fuel for electricity cogen, credit would be given to mills for non-burning of sugarcane in the field (i.e., avoided emissions), as well as the cogeneration surplus power displacing carbon intense fuels such as natural gas or heavy fuel oil used in marginal power generation in Brazil.
- The poor combustion of straw in the fields used in cane production by including some of the non- CO_2 gaseous emissions such as CH_4 and N_2O . But the ash and soot that is emitted into the air via this uncontrolled combustion should also be considered. We would expect these relatively dark particles to absorb more energy either in the atmosphere or on the ground once it lands. This albedo effect may be significant and should be considered. (TESORO1)

Response: Some of these comments are responded to elsewhere in the Lifecycle Analysis section. The straw yield issue is addressed in Comment K-83, the lime production issue in the response to Comment K-85, the truck capacity issue in the response to Comment K-84, and the mechanical harvesting issue in the responses to Comments K-73, K-74, and K-76. The comment maintains that correctly accounting for the use of bagasse results in a carbon intensity of 1.1 rather than $1.9\text{ gCO}_2/\text{MJ}$ for sugarcane ethanol production. Because no information in support of this contention was submitted, staff is unable to re-evaluate its current value. (see also the response to Comment K-61).

This assertion that the Board should adopt verifiable mechanisms to ensure that the best carbon mitigation strategies are rewarded may be based on a misunderstanding of the structure of the LCFS. As a performance-based regulation, the LCFS leaves decisions about how to reduce fuel carbon intensity up to producers and suppliers. It does not impose best practices upon the fuel sector. Market mechanisms in the form of tradable credits do exist to reward fuel innovators, and providers who are not using the practices their periodic reports claim they are using are subject to enforcement

provisions, but the LCFS does not impose a set of best practices or mitigation measures on providers.

In response to the remaining comments, the ARB analysis reflects current practices based on data provided by the sugarcane industry. Additional pathways were developed and incorporated into the Lookup Table for mechanized harvesting and for electricity co-product credit from co-generating facilities. CA-GREET accounts for GHG emissions resulting from the combustion of straw in the fields where mechanical harvesting is not employed. The model considers all of the GHG species listed above except for black carbon (ash and soot). At this time, the ARB has not listed black carbon as a contributor to climate change.

As new data become available, the issues raised in this comment will be reevaluated during the periodic reviews. The LCFS mandates program reviews in 2011 and 2014. Updates to current fuel production practices can be included at this time.

K-112. Comment: The Intergovernmental Panel on Climate Change (IPPC) calculates direct N₂O emissions as 1.25 percent of total nitrogen fertilizer applied, and is currently used as a standard by many universities and industry researchers. The GREET life cycle greenhouse gas emissions model from Argonne National Laboratory uses 2.0 percent. (NCGA)

Response: See response to Comment K-81.

K-113. Comments: The letter from several University scholars to the ARB Chairwoman stated the “GHG of corn ethanol lifecycle analysis is ranging from 100 to 200 g/MJ” while CARB only estimated 75 to 90 g/MJ in their corn ethanol pathway document (CBE3).

Response: The Board’s corn ethanol carbon intensity value was calculated using the best available information and analytical models (CA-GREET and GTAP). Most higher-end lifecycle carbon intensities are based on land use change emission levels that are significantly higher than those used by ARB staff. As the ISOR states, the Board believes that its corn ethanol estimate is likely to be conservative. Based on the wide range of corn ethanol carbon intensity estimates (some with land use change components as low as zero), the Board directed the staff to convene an expert workgroup to refine and improve the land use change analyses supporting the LCFS, and to provide recommendations to the Board by January 1, 2011. The Board has also mandated two program reviews to be completed in 2011 and 2014.

K-114. Comment: This path is based upon UOP Process Data. It is for renewable diesel produced via hydrogenation technology known as the UOP-HDO standalone hydrogenation process for renewable diesel II. Neste’s NExBTL process data has not been used in this study. Neste Oil will submit Method 2 pathways based upon its production facility sites and feedstocks at the appropriate time.

One difference in pathways between the UOP and Neste's actual case study is the way hydrotreatment and hydrogen production are integrated into Neste's refinery site. Neste explained the allocations in its NExBTL study (page 34). Integrating systems gives certain benefits concerning energy efficiency and GHG emissions. This is very productive way to decrease emissions and should be encouraged. We doubt that these allocations are taken into account in CARB's Renewable Diesel study.

The CA-GREET methodology assumes that VOC and CO are converted to CO₂ in the atmosphere and includes these pollutants in the total CO₂ value using ratios of the appropriate molecular weights. Neste's study used the International standard ISO 1464 definition of greenhouse gases. Neste's reporting is based on its guidance under which VOC and CO are not included in greenhouse gases. VOC and CO have also other health, safety and environmental impacts and these gases are treated separately.

In the Esterified Soy oil study the preliminary indirect Land Use Change (iLUC) GHG component is estimated to be 42 gCO₂e/MJ of Biodiesel. Because Renewable Diesel yields more energy per acre than Biodiesel, the iLUC component for Soy-based Renewable Diesel should be 40 gCO₂e/MJ if 42 is the right GHG component for Soy-based Biodiesel.

In Soybean to Renewable Diesel, ARB should give credit to energy and fossil CO₂ to co-products: propane. By doing that, it will reduce the CO₂ emission, credit in the pathway simplify tracking and reporting process. Compared soybean biodiesel and RD, GHG of RD should be lower than BD. This is because BD received 3.7g CO₂e/MJ of glycerin credit, while RD did not receive any credit for propane (4.22 g by calculated). Furthermore, the allocation of energy use and emissions to soybean meal are inconsistent: e.g.: half of energy used in soy oil transesterification (167,986 Btu/MMBtu) was assigned to soybean meal (which is not a co-product and should not be claimed as credit). This problem was due to the mixed use of two sets of allocation fractions, subsystem-based and whole-system-based. As a result, energy use and emissions were allocated to soybean meal twice in the LCA – one for soy oil extraction and the other for transesterification allocations at various LCA steps. (A2O4NESTE1, CONOCO)

ILUC of soybean biodiesel is estimated at 42 g/MJ, but to convert the same volume of soybean to RD it need 4% less energy required. (A2O4NESTE2 -

Without the ILUC debit it takes a 14% blend of soy-based biodiesel to satisfy the 2020 LCFS. Currently most diesel engine manufacturers are comfortable with a 5% blend. Some have accepted a 20% blend. But few are comfortable with the 36% blend that is needed in 2020 if the preliminary estimate of 42 gmCO₂e/MJ ILUC impact survives the regulatory process. (A2O4NESTE1)

Comment: Assuming a soy bean yield of 40 bushels/acre the Biodiesel energy yield per acre is calculated as follows: $(40 \text{ bu beans/acre} * 60 \text{ lbs beans/bu} * 119550 \text{ Btu/gal biodiesel}) / (5.7 \text{ lbs beans/lb soy oil} * 1.04 \text{ lb soy oil/lb biodiesel} * 7.4031 \text{ lb biodiesel/gal biodiesel} * 948.4516527 \text{ Btu/MJ}) = 6893.25 \text{ MJ/acre}$. Assuming the same soy bean yield the Renewable diesel energy yield per acre is as follows: $(40 \text{ bu beans /acre} * 60 \text{ lbs beans/bu} * 122887 \text{ Btu/gal biodiesel}) / (5.7 \text{ lbs beans/lb soy oil} * 1.17 \text{ lb soy oil/lb renewable diesel} * 6.4934 \text{ lb renewable diesel/gal renewable diesel} * 948.4516527 \text{ Btu/MJ}) = 7180.74 \text{ MJ/acre}$. Because land use change is the same for both Biodiesel and Renewable Diesel and iLUC is measured in gCO₂e/MJ the iLUC estimate for Renewable Diesel is equal to $(6893.25/7180.74)*42$ or 40 gCO₂e/MJ. (A2O4NESTE1)

Comment: Because land use change is the same for both Biodiesel and Renewable Diesel and iLUC is measured in gCO₂e/MJ the iLUC estimate for Renewable Diesel is equal to $(6893.25/7180.74)*42$ or 40 gCO₂e/MJ. While this correction helps a little bit, we remain concerned that the huge estimated theoretical iLUC factor will discourage the economic development of one of the few, if not the only, cleaner burning renewable fuel strategies that reduces NO_x emissions. (A2O4NESTE1)

Comment: Some life cycle analysts are concerned about mixing allocation (the primary methodology for both biomass-based diesel pathways.) and substitution methodologies (fossil carbon credit in Biodiesel pathway) in the same pathway. This can be resolved by reducing the fossil energy and CO₂ credits by the amount of fossil energy and CO₂ that was allocated to the co-products. The Neste LCA's we mentioned earlier that integrate hydrogen production essentially does this. This will probably result in a small amount of the carbon content of biodiesel being considered to be fossil carbon. But, the use of consistent allocation methodologies for both types of biomass-based diesel fuel add credibility to the LCFS. (A2O4NESTE1)

Comment: The allocation of energy use and emissions to soybean meal co-product in soy biodiesel and renewable diesel pathways seems problematic and needs to be resolved. This inconsistency in co-product allocation has caused a significant impact on the CI values for soy biodiesel and renewable diesel. For example, more than half of the energy use in soy oil transesterification process, 167,986 BTU/MMBTU (46% of total energy use in the entire LCA), was assigned to soybean meal, which is not a co-product of this step. This problem was due to the mixed use of two sets of allocation fractions, subsystem- based and whole-system-based allocations at various LCA steps. The sub-system allocation fractions were applied in the soybean farming step; while the whole-system allocation fractions were used in the soy oil extraction and transesterification (hydrogenation for renewable diesel) steps. As a result, energy use and emissions were allocated to soybean meal twice in the LCA – one for soy oil

extraction and the other for transesterification. This allocation methodology is incorrect by the LCA principles. Soybean meal is not a co-product of the transesterification process and should not claim any co-product credit in this step. (CONOCO)

Comment: For both the soy biodiesel and renewable diesel pathways, the energy use in soy oil extraction, 4,309 BTU/lb oil extracted was nearly half of the value reported in the 1998 NREL Urban Bus study (8008 BTU/lb of oil extracted. This number needs to be verified and the proper reference needs to be supplied. (CONOCO)

Comment: For both the soy biodiesel and renewable diesel pathways, the default CI values for soy oil production (soybean farming, transport and oil extraction) appear to be different. These values should be the same as they represent the same soy oil feedstock. (CONOCO)

Response: This comment provides suggestions for the development of soy biodiesel and renewable diesel pathways. ARB staff is currently in the process of updating these pathways and will consider these comments as they proceed. Staff will be updating both the direct life cycle analysis (using CA-GREET) and the land use change modeling (using GTAP). The results will be released for public comment. For cases in which specific processing conditions differ from the conditions described in the Board's pathway documents, the affected producer may apply to the Board for the creation of a new sub-pathway under the Method 2A provisions of the regulation.

The observation that CA-GREET treats VOC and CO as GHGs is correct. The model accounts for emissions of these gases in the lifecycle analysis. Propane, a co-product of the renewable diesel process received an appropriate co-product credit in the Board's previous pathway analysis. Future analyses will continue to credit propane as a co-product in all pathways that yield that gas.

K-115. Comment: CARB admits that its preliminary efforts to determine the CI of soy biodiesel are likely to be significantly wrong, yet its economic analysis is based on this significantly wrong assumption. The CARB assertion that the diesel CI specification in the LCFS will not result in price or supply impacts to consumers is simply not credible. (AB32IMPG2)

Response: Preliminary efforts to determine the CI of soy biodiesel are not expected to be significantly wrong. The number is however expected to be slightly different from the early estimate. In addition, it is too early to know if ARB estimates for impacts on price or supply to customers are high or low. The current use of waste and tallow for biodiesel and renewable diesel is not experiencing this effect or their use would be minimal as there is not a mandate in effect. The draft for soy renewable diesel is being modified and will include changes to the transport and distribution modes for renewable diesel; this analysis is expected to be released soon. The transportation of renewable diesel can be through pipelines; however, if the production of renewable diesel is from

remote bio-refineries, it must be transported by barge and trucked to the oil refinery. This is the current situation, if changes occur, the appropriate refinements could be considered. It is to be noted that transport and distribution of renewable diesel in its present form generates only a small portion of the total WTW GHG emissions. Changing a small fraction to pipeline is not expected to result in any significant changes in the carbon intensity for this fuel.

K-116. Comment: For the soy renewable diesel pathway, barge and heavy diesel trucks are used for the transport and distribution of renewable diesel. One of the advantages of renewable diesel fuel is its compatibility with existing pipelines. Therefore, transportation of renewable diesel via pipeline should be included in its LCA. This should result in lower carbon intensity for renewable diesel. (CONOCO)

Response: The draft soy renewable diesel is being modified and will include changes to the transport and distribution modes for renewable diesel. This analysis is expected to be released soon. As for pipeline transportation, there are no known renewable diesel plants in California at the present time. When such plants are commissioned and pipeline transfer can be demonstrated, appropriate refinements could be considered. It is to be noted that transport and distribution of renewable diesel in its present form generates only a small portion of the total WTW GHG emissions. Changing a small fraction to pipeline is not expected to result in any major changes in the carbon intensity for this fuel.

K-117 Comment: The allocation of energy use and emissions to soybean meal co-product in soy biodiesel and renewable diesel pathways seems problematic and needs to be resolved. This inconsistency in co-product allocation has caused a significant impact on the CI values for soy biodiesel and renewable diesel. For example, more than half of the energy use in soy oil transesterification process, 167,986 BTU/MMBTU (46% of total energy use in the entire LCA), was assigned to soybean meal, which is not a co-product of this step. This problem was due to the mixed use of two sets of allocation fractions, subsystem-based and whole-system-based allocations at various LCA steps. The sub-system allocation fractions were applied in the soybean farming step; while the whole-system allocation fractions were used in the soy oil extraction and transesterification (hydrogenation for renewable diesel) steps. As a result, energy use and emissions were allocated to soybean meal twice in the LCA – one for soy oil extraction and the other for transesterification. This allocation methodology is incorrect by the LCA principles. Soybean meal is not a co-product of the transesterification process and should not claim any co-product credit in this step. (CONOCO)

Comment: For both the soy biodiesel and renewable diesel pathways, the energy use in soy oil extraction, 4,309 BTU/lb oil extracted was nearly half of the value reported in the 1998 NREL Urban Bus study (8008 BTU/lb of oil extracted).

This number needs to be verified and the proper reference needs to be supplied. (CONOCO)

Comment: For both the soy biodiesel and renewable diesel pathways, the default CI values for soy oil production (soybean farming, transport and oil extraction) appear to be different. These values should be the same as they represent the same soy oil feedstock. (CONOCO)

Response: Staff is currently updating the soyoil to biodiesel analysis. Co-product allocation methodology in CA-GREET is being updated to be consistent with the GTAP analysis for land use change impacts. The whole system and sub-system allocations are not being used in the updated analysis and therefore any potential dual-crediting or other inconsistency in the pathway analysis which the commenter refers to here will not be a concern.

The soyoil extraction is smaller than the one in the NREL study since there was an error in the original Argonne model. The model counted natural gas twice: once for natural gas use for combustion to produce steam for the oil extraction process and also counted all the energy use and emissions to produce steam. This was corrected and hence the lower energy used in the soyoil extraction step.

The commenter correctly indicates that the CI should be the same starting from feedstock production to soyoil extraction. However, the allocation factors for the two fuels are different thereby reflecting different CIs for the two fuels though produced from the same feedstock.

K-118. Comment: CARB fails to acknowledge and incorporate in the LCFS rulemaking a variety of ongoing and emerging technical advances that continue to improve ethanol's fuel cycle energy balance and carbon footprint. For example, CARB ignores significant progress taking place in the Netherlands with hydrous ethanol, which is being shown to effectively replace today's anhydrous ethanol specification with attendant cost, energy and carbon emission reductions. A fairer more progressive approach by CARB would at least take note of and examine advances like this that stand to enhance the ethanol fuel cycle. Others, including the State of Louisiana, have moved to test and evaluate hydrous ethanol. (MDSA)

Response: The emphasis in developing fuel pathways is to provide fuel suppliers with approved carbon intensity values to use in preparing their periodic reports to the Board under the LCFS. Staff's priority, therefore, is to develop pathways for *existing* and *available* fuels. At present, hydrous ethanol cannot be used as a vehicle fuel in the U.S. Thus, development of a hydrous ethanol pathway is not a current priority. At the same time, the LCFS is structured to stimulate the development of lower-carbon fuels for the California market. As providers prepare to bring such fuels to market, they can apply to the Board for the establishment of new pathways under the Method 2A and 2B

provisions of the LCFS regulation. As new pathways are approved under this process, fuel providers are able to use them in their LCFS reporting to the Board.

K-119. Comment: The CARB model assumes ethanol yields of 250 gallons/acre of switchgrass. However, there are recent field trials and experimental data to support a more realistic yield range of 400-720 gallons/acre, requiring 22.2 to 40 million acres of switchgrass to meet the RFS demand for cellulosic ethanol—at least 1/3 fewer acres than is indicated by the CARB report. (DUPONT1)

Response: The cellulosic pathway analysis presented in the ISOR is preliminary. Staff is currently developing a more detailed analysis for public comment. In developing that analysis, staff will consider the points raised in the above comment. The ethanol yield value used in the preliminary analysis was the midpoint from the range of values available in the literature. In general, the initial pathway approved for a new fuel type is prepared using values that reflect prevailing production processes rather than innovations in the early stages of adoption. The goal is to provide existing producers with values they can use in preparing their periodic reports to the Board under the LCFS. As producers recognize the need for additional pathways, however, they may apply to the Board for the establishment of those pathways under the Method 2A and 2B provisions of the LCFS regulation. As new pathways are approved under this process, fuel providers are able to use them in their LCFS reporting to the Board

Additionally, the Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014 which will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are warranted.

K-120. Comment: When the cellulosic ethanol indirect land-use issues are fully analyzed, it will be apparent that this type of fuel, like corn ethanol, also suffers from a negative carbon ratio. It remains questionable whether the energy ratio for cellulosic ethanol will ever be positive on a commercial scale. It is good that the LCFS is committed to examining life cycle issues for all fuel pathways. (AIR)

Response: Thank you for the positive comment concerning our commitment to examining life cycle issues for all fuel pathways. The LCFS does not use a 'carbon ratio' metric. It uses a gCO₂e/MJ metric which is calculated from a Well-to-Wheel pathway analysis of a transportation fuel. As for cellulosic ethanol, the analysis presented in the ISOR was a draft version. Staff is in the process of collecting additional data on feedstock production and conversion processes and the GTAP analysis for land use change impacts is also being refined. An updated analysis will be made available for public comments in early 2010. We expect the various lifecycle assessments for cellulosic ethanol will differ appreciably depending on the source of cellulosic feedstock and the corresponding potential for land use change emissions. Based on currently published reports by the NREL and other agencies, there is expectation for low carbon cellulosic ethanol to become commercially available beyond 2010.

K-121. Comment: One important point not yet fully studied is the use of agricultural and forest residues in any large quantity. This will generally not be sustainable or energy efficient because agricultural residues must be returned directly to the soil for long term fertility to be achievable. In the carbon reduced future, fossil fuel based fertilizer will need to be phased out and the only other means of maintaining crop output is to build up and maintain organic matter in the soil and not deplete it by taking crop residues off the land. It is logical that returning crop residues to farmland is far more energy efficient than collecting, transporting and then processing it into a fuel and supplementing the farmland with other sources of nutrients. There is also the obvious fact that increasing organic matter in the soil also sequesters carbon in huge quantities. (AIR)

Response: We recognize that redirecting agricultural waste to fuel and supplementing soil nutritional requirements by using fossil fuel derived fertilizer is not a desirable outcome. The potential increase in the use of fertilizers or other soil amendments will be investigated in the lifecycle assessment for cellulosic fuels derived from agricultural residues. We also agree that the benefit of carbon sequestration from building organic matter in soil is a desirable outcome. In approving the ISOR, the Board directed staff via Resolution 09-31 to address necessary sustainability criteria for the LCFS regulation. All of these issues including the one above can be addressed in the effort to develop sustainability criteria for the production and use of fuels for the LCFS, as directed by the Board in Resolution 09-31.

K-122. Comment: The fermentation processes do not include nutrients – specifically DAP (Diammonium phosphate) and lime (for pretreatment and neutralization), which have both CO₂ and N₂O footprint in their manufacture. (CONOCO)

Response: The aggregate energy use data used in CA-GREET for ethanol production accounts for all inputs to the process including nutrients. The corresponding breakdown of energy type (or fuel shares in CA-GREET) accounts for both the use and the upstream emissions based on the weighted fuel shares for the process.

K-123. Comment: The assumption for ethanol yields, 90 gallons per ton biomass for both forest waste and farmed trees, is overly optimistic. The most recent NREL report uses an average value is 55-60 gallons/dry ton for wood as a feedstock. (CONOCO)

Response: The pathway assessment documents for cellulosic ethanol presented on the LCFS website are preliminary. We are currently updating these lifecycle assessments using more current data. The results will be included in the Lookup Table following the necessary rulemaking process.

K-124. Comment: The proposed default value for California Ethanol is below the comparable baseline for gasoline. The proposed default Lookup Table will directly incentivize the siting of bio-refineries in CA.

At the March 27, 2009, LCFS workshop, ARB staff expressed that customers will decide the winners on the market by picking vehicles and fuel. Customers may not know the drive train efficiencies or carbon intensity requirements to maximize technological feasible reductions. By allowing every fuel to compete, and not excluding the fuels that we already know are highly polluting, the ARB will waste an incredible opportunity to truly push for a coordinated zero-carbon system, and protracts a lot of economic and political pain. In effect, ARB staff is picking winners and losers every day as they pick which values to employ among competing self-interests. For instance, the ISOR describes that in computing one input, ARB staff and GTAP modelers assume that 25 percent of the carbon stored in the soil is released when land is cultivated. We believe this value is a reasonable compromise given the variability in data (emphasis added). This great scientific uncertainty and lack of metrics, objectives, or guidelines will create a free-for-all fuel situation with a long trail of stranded investments during initial uncertainties. When there are marginal differences in values between particular fuels on the Lookup Chart, we believe the ARB invites financial incentives for fraud, being flooded with opt-in values to get under the baseline, and the agency having to make compromises, subject to competition from new fuel challengers. (CERA1)

Response: In terms of reducing fuel carbon intensity, a policy designed to reward only the lowest-carbon alternative fuels (such as hydrogen and electricity), or to exclude all higher-carbon alternative fuels, would seem to be the most effective choice. Unfortunately, the necessary fuels and the vehicles to utilize them are not expected to be available in significant numbers for another ten years—too late to contribute to the reductions called for under the LCFS. The approach taken by the LCFS, on the other hand, will achieve significant fuel carbon reductions over a shorter time horizon. In addition, the technologies incentivized by the LCFS in the short term will enable greater long-term GHG reductions than would have otherwise been possible.

The commenter is correct that the LCFS approach allows biofuels to earn credits—so long as they are found to have carbon intensities that are verifiably below those of the relevant reference fuel. Of the fuels that earn credits, however, those with the lowest carbon intensity earn the most credits. Although higher-carbon alternative fuels, such as corn ethanol, will have a short-term presence in the California market, the role of non-crop-based fuels (such as those produced from agricultural and municipal waste streams) will increase.

The siting and construction of biorefineries within California, and nationwide, will be driven largely by the Federal Renewable Fuel Standard (RFS2). The RFS2 requires the production of 15 billion gallons of corn ethanol, and lesser amounts of lower-carbon fuels, by 2015. The necessary biorefineries will be constructed when and where the producers deem them to be the most economically advantageous.

Three mechanisms will prevent the undesirable outcomes described in this comment from occurring: First, Fraud will be prevented by the requirements for scientifically verifiable evidence in support of pathway development, in concert with the Boards existing verification and enforcement programs. Second, carbon intensity changes are subject to the full California rulemaking process. This will minimize stranded investments and other negative effects from fluctuating carbon intensity values. Third, new fuel pathways created under the Method 2A process must meet what are known as “substantiality” requirements: To be approved, a new Method 2A pathway must reduce the carbon intensity of the primary pathway by five gCO₂e/MJ, and must be able to be produced in volumes of at least 10 million gallons per year. Moreover, the Board expects no more about 300 new pathway applications as the regulation comes into effect. This number reflects the number of corn-to-ethanol and bio-digester facilities expected to be operational when the regulation goes into effect. This is a manageable number of applications.

K-125. Comment: We are also concerned that the lifecycle analysis of the natural gas pathway does not fully account for GHG emissions. The primary constituent of natural gas is methane. Methane is 25-times more potent than CO₂ as a greenhouse gas. As liquefied natural gas in fuel tanks warms, methane is released to the environment through a pressure relief valve. The venting of methane could result in a net increase in greenhouse gas emissions compared to diesel fuel. The LCFS is unclear as to whether the release of natural gas from on-board tanks has been accurately quantified. (ATA)

Response: ARB staff investigated the GHG impacts of fugitive natural gas and found that venting to relieve pressure build-up in LNG vehicle fuel tanks is insignificant for in-use vehicles. Emissions are also decreasing over time due to advances in the design of the materials and components used in on-board tanks. The result has been reductions in the heat transfer that leads to gas vaporization.

K-126. Comment: As LNG in fuel tanks warms, methane is released to the environment through a pressure relief valve. The venting of methane could result in a net increase in greenhouse gas emissions compared to diesel fuel. (ATA)

Response: See also response to Comment K-125. In evaluating the full lifecycle emissions of LNG used in heavy-duty vehicles, staff investigated the likelihood of fugitive emissions from LNG regasification from stationary vehicles. Based on a review of the available information, staff concluded that, for vehicles that are regularly operated, venting from pressure build-up is not required. Overall, therefore, venting impacts from LNG-powered heavy duty vehicles are insignificant. Venting that does occur will decrease over time through the use of insulation and other thermal management techniques.

K-127. Comment: CA-GREET assigned the distance of crude and fuels transportation too large (for large refineries). Small refineries fuels transport is about 30 miles to stations. Because small refiners' plants are less complex and

less energy intensive than large refineries, it follows that small refiners produce less GHG emissions. The DOE Energy data shows that a typical large refiner energy use is 50 percent greater than that of a "comparable" small refiner (KORC1)

Comment: Paramount uses less energy than major oil companies in CA because it is a non-cracking facility (half of the fuel used to produce a gallon of crude based products) resulting in CI less than 90 g/MJ (using the same method, but higher efficiency by data of 2008) (PP1)

Comment: And we feel like we're being penalized by using an average that's currently being used just cause we're so small. We may have nothing to do with the average. As you can see up there, we think we're already half way to the target for the 2020 LCFS standard without even doing anything. (PP2)

Comment: These small refineries are at a competitive economic disadvantage, that is, the rules cost more cents per gallon for these smaller refineries than it does for the large complex refiners. Not only is the energy efficiency and carbon intensity reduced from the small refiners, but also there are -- it's a double whammy because these refineries are complying with the Low Carbon Fuel Standard from a common baseline with credits and alternative fuels. And because of logistics, scale, and access to capital, they are at a disadvantage in the compliance side as well. (WIRA)

Response: The distance used is an average distance for all fuels transported. ARB recognizes that likely differences exist between large and small refineries in terms of energy use and GHG emissions and that differences in energy use and GHG emissions exist between large refineries themselves. However, to maintain the fungibility of fuels, a decision, approved by the Board was made to use an average carbon intensity value for petroleum-based fuels. The Climate Solutions Act (AB 32) will result in the regulation of GHG emissions from refineries in CA and will likely lead them to conform to average California specifications. The Board approved LCFS requires mandatory regulatory reviews in 2011 and 2014 which will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate. As for small refiners, this can be reviewed during the mandatory program reviews. There are no data to support the argument that there is a cost differential for small refineries. The ARB analysis shows that compliance costs will not be significant. Compliance will be achieved mainly by the purchasing of different biofuels and other alternative fuels with CI lower than gasoline. It is expected that the costs of purchasing would be the same for all fuel producers large or small. See also response to Comment C-229.

K-128. Comment: In the past fuels rulemaking, I've been before your Board pointing out that these [small] refineries are at a competitive economic disadvantage, that is, the rules cost more cents per gallon for these smaller refineries than it does for the large complex refiners. Here, however, less complexity means lower

energy use per gallon. Lower energy use in the refining process means a lower carbon intensity per gallon. The staff proposal, however, sets one baseline for everyone, even though WIRA members are probably about halfway to the endpoint. And this is the one time the simple refining operation can be an advantage, and we're very disappointed that the proposal precludes this opportunity. The proposal would allow alternatives to the numbers on the alternative fuel side and those can be adjusted, but not the baseline for gasoline and diesel. And we feel that's wrong. (WIRA)

Comment: Upon review of the proposed LCFS, it appears Kern is being disproportionately impacted by the method CARB has used to develop weighted averages of various stages of the life-cycle analysis. For example, Table 2.01 of the draft GREET Pathway uses "average crude" for CARBOB and diesel, and assigns a weighted average of 7,093 miles for the distance "average crude" supply travels in tankers, 442 miles "average crude" travels by pipeline, and 200 miles "average crude" travels by barge. The vast majority of Kern's crude supply travels only approximately 30 miles from the local oil and gas production fields to Kern's refinery. (KORC1)

Comment: Because small refiners' plants are less complex and less energy intensive than large refineries, it follows that small refiners produce less GHG emissions. To illustrate, based on EPA AP-42 Compilation of Air Pollution Factors, Volume 1: Stationary Point and Area Sources, it is apparent the large refiners operating fluid catalytic crackers, hydrocrackers, isomerization units and cokers have significantly higher total hydrocarbon emissions factors assigned to those units than small refiners that typically do not operate such complex and energy intensive units. Small refiners operate more energy efficient units such as hydrotreaters and reformers. (KORC1)

Comment: Kern oil agrees with the board that "the carbon intensity values represent the currency upon which the LCFS is based". Kern can demonstrate that the complexity, location and supply to its small refinery, yields an inherently lower carbon intensity than the average refinery utilizing the average crude oil. A straightforward review of the greet model and simple calculations from transportation and crude refining energy mix at small refiners yields a reduction of more than 2 grams of CO₂ equivalents per megajoule for both gasoline and ULSD.

The small refiner is commonly disadvantaged by economies of scale in its operation, and by less access to capital and credit. Now we are disadvantaged in the LCFS "currency", by utilizing a higher carbon intensity than which is appropriate. (KORC4)

Comment: Refinery efficiency as established in the LCFS is not correct and unfairly punishes less complex [i.e., small] refiners. The starting point used by the GREET model developers (Michael Wang et al, Argonne National

Laboratory) to determine refinery process CO₂ emissions the model assigns to CARBOB and CARB diesel is based on an estimate of the overall efficiency of the average refinery. The process used is described in the document, "Estimation of Energy Efficiencies of U.S. Petroleum Refineries"

http://www.transportation.anl.gov/modeling_simulation/GREET/pdfs/energy_eff_petroleum_refineries-OS-08.pdf.

There is currently very little public information regarding the efficiencies of individual refineries. The Argonne methodology uses Energy Information Administration (EIA) public data aggregated to a regional or national level. There are two weaknesses to this methodology that create obvious uncertainty in CARB's proposed carbon intensity baselines for CARBOB and CARB diesel to the LCFS.

As the document referenced above states, the EIA does not survey refiners for hydrogen use or natural gas use for captive hydrogen production. Argonne used an estimate of refinery hydrogen usage from the SRI Consulting Chemical Economics Handbook. The method also requires estimates of the average energy content for each refinery feedstock and product listed in the EIA report. These are also numbers that aren't collected by survey, but are estimated because refiners don't measure the energy content of either feedstocks or products, which adds further uncertainty to the calculated refinery efficiency. Using the described method, the efficiencies of Paramount's facilities were calculated. (PP1)

Comment: Using this methodology, Paramount has a calculated efficiency above 96% which is substantially more energy efficient than the average California refinery. Using the average energy intensity factors from the latest 2008 Argonne work on refinery efficiency (http://www.transportation.anl.gov/modeling_simulation/GREET/pdfs/energy_eff_petroleum_refineries-03-08.pdf) combined with Paramount's refinery efficiency, the Paramount product efficiency factors are calculated as 93.7% for CARBOB and 95.1% for CARB diesel. Even after these efficiencies are adjusted downward by a percent to "California-ize" (the GREET v1.8 model product efficiencies were reduced slightly to account for depentanizer power (for CARBOB) and additional hydrogen (for CARB)), Paramount almost has an 8% higher efficiency than the values used to establish the baseline value for LCFS. In other words, Paramount (and other non cracking refineries) use about half the fuel of the average refinery in California to produce a gallon of crude oil based products.

Since the refining portion of the lifecycle for CARBOB represents about 14% of the CO₂ emitted, the higher efficiency of Paramount's low energy process means Paramount's products will emit about 7% less CO₂ than the LCFS baseline. The grams CO₂ equivalent/Megajoule (gCO₂e/MJ) for Paramount's CARBOB and CARB are calculated to be less than 90. As a result, we believe Paramount's

products are already more than halfway to the 2020 target goals of 86.3 and 85.2 gCO₂e/MJ.

This reduced complexity is, as previously documented, a competitive economic disadvantage to Paramount. CARB should not also punish Paramount by ignoring the lower carbon intensity of the gasoline and diesel fuel it produces which results in part from its inability to raise sufficient capital to purchase and erect a more complex cracking unit. It is rare that Paramount's economic disadvantage can be beneficial, but in the case of the LCFS, Paramount's relative simplicity results in less energy consumed per gallon of product. (PP1)

Comment: In addition, to require Paramount to reduce the carbon content of its fuels from a lower starting point than the major oil companies is to further penalize Paramount by grouping it with inefficient high energy heavy oil cracking processes used by all major oil companies. Paramount simply wants to be treated equitably in this LCFS adoption process and wants CARB to note that as a result of its simplistic refining process, it bears very little resemblance to larger complex California refineries. (PP1)

Response: Issues with regard to small refiners like Kern Oil and Paramount Petroleum have been addressed in response to Comments C-118, C-123, C-135, I-20, and K-127.

K-129. Comment: CARB staff should be commended for its use and on-going refinement of the GREET model to quantify direct impacts. A LCFS regulation based on direct impacts as quantified by the CA GREET model should be implemented starting in 2010. However, the co-products credit analysis and the ILUC portion of the regulation have not been afforded the same rigor. The fact that they haven't reflects poorly on the credibility of the entire regulation. (SHAFFER1)

Response: The lifecycle analysis including the co-product treatment was based on the Argonne GREET model which has been peer-reviewed and used by a number of governmental and private entities. The co-product analysis presented in the ISOR was developed in consultation with all stakeholders over the course of several workshops during the regulatory development process. The GTAP model was also extended to include a co-product module to account for benefits from co-products of fuel feedstock. Because the analysis presented in the ISOR benefitted from such thorough vetting, and from the submission of so many comments, the Board has deemed it to be sufficiently robust to serve as the basis of a final LCFS regulation. In approving staff recommendations at the Hearing in April 2009, the Board directed staff to convene an Expert Workgroup to consider land use modeling issues, review and refine these, if appropriate, and make recommendations to the Board by December 2010. The Board approved LCFS requires mandatory reviews in 2011 and 2014 at which time any refinements could be considered.

K-130. Comment: Hydrogen production should be fully accounted for in the gasoline

and diesel pathways. California refineries consume prodigious quantities of merchant hydrogen essential for CARB RFG and ULSD production. (SCAQMD)

Response: Use of hydrogen required to process the feedstock to produce these fuels has been accounted for in the CA-GREET analysis presented in the pathway documents.

K-131. Comment: The assumption for hydrogen compression efficiency (92%, Section 5.1) is very high. According to Praxair estimates (reference available) hydrogen compressor efficiency is typically 70%. (CONOCO)

Response: The CA-GREET value was used based on analysis from the hydrogen highway studies conducted in California in 2005 which used work published by NREL. As for the 70 percent efficiency being cited by the commenter, we do not know the specifics of the process and also we do not know how efficiency is being defined by the cited source.

K-132. Comment: The CA GREET Model and the Electricity Report shows the MWh Shares of “Marginal Electricity” as 78.7% Natural Gas and 21.3% Renewable, but in the calculation in the Electricity Report the MWh shares are shown as 43.1%. In the Electricity Report, the MWh Shares in table 2.02 need to be revised to 78.7% and Average Efficiency (LHV) should be 51.8%. Also show calculation for “Others”. (HONDA)

Response: The CA-GREET model used the correct values of 78.7 percent for the natural gas share, and 21.3 percent for the renewable share. The 43.1 percent share value appearing in the electricity pathway document is erroneous, and will be corrected. The WTT analysis used to produce the Lookup Table value was CA-GREET-based, and was not affected by the error in the pathway document. The entries in tables 2.01 and 2.02 of the Electricity pathway document¹³ (pages 19 and 20) also contain errors. They should reflect 100 percent use of combined cycle natural gas combustion turbines and renewables (wind, solar, etc.) for all other energy needs. The average plant efficiency should be 51.8 percent. As indicated previously, this error in the pathway document does not impact the WTT analysis used to produce lookup table values..

Electricity

K-133. Comment: For the California electricity pathway, questions have been raised on the assumption for marginal electricity. It is expected that the use of plug-in hybrids will impact the production capacity in California, and additional electricity is needed. The source of fuel (natural gas or coal?) for marginal electricity has been debated. The current draft assumes 70 percent natural gas and 30 percent biomass but provides no explanation how the values were determined. The draft also assumes biomass would come from waste materials in agricultural and forest industries. A feasibility study is necessary to validate the assumption of

¹³ See the electricity document at: http://www.arb.ca.gov/fuels/lcfs/022709lcfs_elec.pdf

30% biomass for power production. (CONOCO)

Response: The analysis presented in the ISOR considered marginal electricity to be 79 percent natural gas and 21 percent renewables (biomass, wind, solar, etc.), based on the provisions of the California Renewable Portfolio Standard (RPS)¹⁴. The analysis in the ISOR considered the projected likelihood of such a distribution by 2010. The regulations implementing the California Global Warming Solutions Act of 2006 (AB 32), will permit neither additional coal-based generation in California, nor the importation of coal based electricity from out-of-State. In October of 2009, the Governor issued Executive Order S-21-09 requiring that 33 percent of California's electricity be produced from renewable sources. The ARB is charged with developing the regulations to implement the Governor's Order. As part of that process, ARB will study the feasibility of meeting the 33 percent target.

K-134. Comment: It is extremely important that CO₂ produced in the course of producing electricity to charge plug-in hybrid or electric only vehicles be properly accounted for in Clean Air Act mandated emission inventories. Even more important, they must be apportioned to, and therefore controlled at, their actual place of use. If not, California could claim plug-in hybrids used in Los Angeles are "emission-free" while the electricity and CO₂ produced to charge them comes from a new or expanded coal-fired power plant located where they will not be included in a relevant inventory. This would result in additional CO₂ being emitted into the earth's atmosphere without any record of these emissions having occurred, subverting the goal of controlling Green House Gas emissions. California Air Resources Board should ensure that any CO₂ regulations include the following:

- a. All electricity and CO₂ generated from coal or other non-renewable fueled power plants used to charge plug-in hybrid or electric only vehicles must be accounted for in Clean Air Act mandated state emission inventories.
- b. Quantities of electricity and CO₂ used for charging batteries must include energy losses (and CO₂ production) incurred in electrical production, step-up/step-down transformers, and long-range transmission, (totaling approximately 60%+ of total electrical production, USNAS).
- c. Calculations must be consistent.
- d. Plug-in Hybrid battery charging electrical CO₂ emissions must be included, along with on-board combustion CO₂ emissions, in point-of-use state mobile source emission inventories no matter where the electricity is produced.

¹⁴ California's Renewables Portfolio Standard (RPS) was originally established by the legislature in 2002. Subsequent amendments to the law resulted in a requirement for California's investor-owned electric utilities to increase their sales of eligible renewable-energy resources by at least 1 percent of retail sales per year, so that 20% of their retail sales are derived from eligible renewable energy resources by 2010. On September 15, 2009, the Governor signed Executive Order S-21-09, which increased the requirement to 33% by 2020, and made the requirement apply to all utilities, including publicly-owned municipal utilities.

- e. Electric only vehicle charging electrical CO₂ emissions must be included in point-of-use mobile source state emission inventories no matter where the electricity is produced. (ABUSA)

Comment: All energy lost (approximately 60%) in the generation and transmission of electricity used to recharge electric and plug-in hybrids must be accounted for. Since most of this is from non-renewable fuels, significant GHG emissions must not be missed. (ABUSA)

Comment: The energy and GHGs used to extract and concentrate uranium to electrical production levels and the energy/GHG and costs required for the secured long-term storage of spent fuel must be accounted for. In addition, the national security costs of relying on imported sources of uranium must be included. (ABUSA)

Comment: The energy and GHGs used to produce batteries for hybrids and electric cars (above that used to produce baseline gasoline vehicles) must be accounted for. In addition, the energy and GHGs required to dispose of batteries in an environmentally neutral manner must be accounted for as well. (ABUSA)

Response: The ISOR has clearly pointed out that the regulated party, in the case mentioned above, is the power plant where the electricity comes from to California. Furthermore, since 2007, the ARB has regulation to mandate the reporting GHG emissions for all largest stationary plants operated in the state. The California Energy Commission routinely updates the electricity source information which provides information even on electricity imported into the state. The pathway document for electricity did appropriately account for imported electricity into the state coming from all generation sources including coal fired utilities. This will therefore accurately account for the GHG emissions irrespective of where the final use is for the generated electricity. The accounting for GHG emissions has utilized the same approach for all fuels considered in the LCFS: global accounting for all GHGs irrespective of where they are produced.

Energy lost in generation and transmission of electricity is accounted for in the CA-GREET model and in the electricity pathway report published February 2009. Uranium-sourced electricity is about 15 percent of the California electricity portfolio. The energy and GHG emissions attributable to this feedstock has also been considered in the CA-GREET analysis. Costs related to procurement and disposal of nuclear fuel is outside the scope of the current regulation. Disposal of batteries in an environmentally appropriate manner will occur based on current regulations in place that mandate such disposal. Currently, the GHG emissions to produce batteries for plug-in hybrid and electric only vehicles have not been considered because they belong to vehicle production side and not part of the LCFS regulation. GHG emissions for the disposal of batteries have also not been considered in a fuel-use directed regulation.

K-135. Comment: The original LCFS estimate for CA Marginal Emission was 104.71 gGHG/MJ. This is lower than the *lowest* estimate of CA Marginal Emissions by UC Davis –109 g/MJ to 162 g/MJ, (136 g/MJ Mean Marginal). (HONDA)

Comment: A thorough analysis by UC Davis estimates the CI of CA Marginal Electricity in the range of 109 g/MJ to 163 g/MJ, depending on the month and time of day. The new results are comparable to the high and low ends of the UC Davis estimate. The real answer for Marginal Electricity in the near term is probably in between. A detailed study should be conducted to determine what this mix is likely to be in the near term as well as in the mid term. (HONDA)

Comment: UC Davis assessed the marginal electricity emissions of the actual installed generation capacity of California using a dispatch model. This yields a detailed, hour-by-hour, month-by-month assessment of the likely emissions from California generation. This research is not finalized (this data is from a poster progress report), but it demonstrates the likely boundaries of the real answer. 104.71 gGHG/MJ is much too low! (HONDA)

Comment: The Plant Shares in the Electricity Report do not match the CA GREET model, and the Electricity Report is inconsistent. It is unclear whether the intent if ARB is to use 100% Natural Gas Combined Cycle Powerplants, or is the intent to use the existing plant share split? (HONDA)

Comment: It is unclear whether the intent is to use 100% Natural Gas Combined Cycle powerplants. Table 2.01, Table 2.02, the paragraph following it, and the CA Greet Model are inconsistent. (HONDA)

Comment: The MWh Share Percent is incorrect in Table 2.02. It should change from 43.1% to 78.7%. As well, the efficiency is listed incorrectly. It should be 51.8%. (HONDA)

Comment: The CI for Marginal Electricity (104.71 gGHG/MJ) is optimistically low. The assumptions behind the CA Marginal Electricity are overly optimistic. EVs charged using off-peak electricity will use EXISTING generation resources, NOT NEW generation resources. Existing natural gas generation has a net efficiency closer to 38.9%, not 51.8%. The actual offpeak marginal generation mix should be used to calculate the emissions impact of this policy. (HONDA)

Response: The analysis presented in the electricity pathway document calculated emissions attributable to marginal electricity generation in California based on the electricity mix likely when the LCFS regulation takes effect. This was based on earlier mandates set by the Governor. In October 2009 the Governor issued an Executive Order which is now mandating 33 percent generation from renewables. If achievable, this is likely to lower the carbon footprint further for California marginal electricity. There are two mandatory program reviews in 2011 and 2014 at which time updates could be considered based on available data.

As indicated by the commenter, the UC Davis study is not a final report and staff has not reviewed all the details of this study to elucidate differences between the analysis in the ISOR and the UC Davis analysis. A detailed analysis of the UC Davis report could also be considered during the program reviews in 2011 and 2014.

The electricity report is not inconsistent, because the analysis considered two different pathways for electricity generation in California: average and marginal. For the average pathway, the details of the contributions from the different generation sources (hydro, nuclear, etc.) was from the California Energy Commission data and has been detailed in the electricity pathway document. For marginal electricity, the analysis used a combination of combined cycle natural gas for the non-renewable component (79 percent) and renewables for the balance (21 percent). Complete details are provided in the electricity pathway document published on the LCFS website (www.arb.ca.gov/fuels/lcfs.htm).

If vehicles are predominantly charged overnight, the appropriate carbon intensity would likely be that of electricity from baseload sources. If, however, vehicles are charged throughout the day and night as needed, the use of average or marginal electricity may be more appropriate depending upon the time of day at which charging occurs. By January 1, 2015 all electricity receiving credit under the LCFS must be dispensed using direct metering. Direct metering will allow for the application of carbon intensity values which vary as the overall resource electricity mix changes with time of day. See also the response to Comment K-132.

K-136. Comment: The ISOR states that the "scope of the standard is designed to capture the diverse fuel portfolio available today and in the near future, while offering a fuel-neutral platform in which alternative fuels can be incentivized without choosing winners or losers (emphasis added)." However, the default "Lookup Table" does in fact pick winners and losers above or below the relative gas or diesel baselines. ARB staff directly picks those winners by calculating the carbon intensity, which can and has become very political given the great scientific uncertainties of calculating soil payback times, land use change impacts, and all of the other uncertainties in calculating lifecycle analysis and land use change that ARB staff continues to analyze. (CERA)

Response: Following a full and open public review period involving multiple public workshops, the evaluation of hundreds of comment letters, and the continuous revision of the LCFS to reflect the many technically sound comments received, the Board has determined that the uncertainty surrounding the LCFS carbon intensity values has been reduced to acceptable levels (this and other Board findings cited in this response can be found in Resolution 09-31). The direct lifecycle carbon intensities, because they are based on energy consumption and emission rate values that have received lengthy and intense scrutiny from industry, academia, and the public, are widely viewed as defensible. Most of the remaining uncertainty in the published LCFS fuel carbon intensity values derives from the land use change increments included in a subset of

fuel carbon intensity values (biofuels produced from feedstocks that displace food crops). As the responses in Section L ("Land Use Change") indicate, however, those values were subjected to the same public vetting and the same comment-driven revision as were the direct lifecycle values. That process convinced the Board that crop-based fuels whose feedstocks displace food crops do create significant land use change impacts, and that staff's analysis of those impacts, as revised throughout the public comment process, has yielded values that are sufficiently certain to be included in the appropriate fuel carbon intensity values. In reaching that finding, however, the Board acknowledged the desirability of reducing as much of the remaining uncertainty around current land use change carbon intensity values as possible. To accomplish that task, it directed staff to convene an expert workgroup to refine and improve the land use change analysis performed under the LCFS, and to provide recommendations to the Board by January 1, 2011. The Board has also mandated two program reviews to be completed in 2011 and 2014. Given the strongly technical basis of the LCFS carbon intensity values, and the lengthy and open public review to which they were subjected—as well as the existence of a Board-mandated ongoing review process—it is simply incorrect to assert that these values are so uncertain that publishing them is tantamount to simply picking winners and losers.

K-137. Comment: The Statement of Reasons states that the Board will be approving the Look-Up Table with the current values. Sempra Energy still has concerns about the accuracy of the pathway and GREET Model data inputs that are used to derive carbon intensities related to natural gas fuels. We appreciate the efforts staff has made to further evaluate these inputs and recognize that this analysis is ongoing. For this reason, we suggest that no values for natural gas fuels be included in the Look-Up Table at this time and that the Executive Officer use the authority provided in section 95486 (XI) to add these values during the next several months. Alternatively, we suggest that a paragraph be added to the Board Resolution of adoption stating that the values for natural gas fuels in the Look Up Table are still being reviewed. (SEMPRA1)

Response: The LNG and CNG pathway analyses from domestic and remote sources of natural gas were published on the LCFS website. Based on comments received, these were updated and subsequently incorporated into the Lookup Table. The analysis for these pathways was based on published data by the EIA, U.S. EPA, the California Energy Commission and other federal and state agencies. Staff feels that the analysis accurately represents the pathway carbon intensities for all the natural gas derived pathways provided based on currently available data. ARB is currently working on a survey to estimate GHG emissions from the production, transmission and distribution of natural gas in California. Based on the data from this study, appropriate refinements could be considered during the mandatory program reviews in 2011 and 2014.

K-138. Comment: On Page III-I I the following statement appears: "LNG is generally transferred to specially designed and secure storage tanks and then warmed to its gaseous state- a process called regasification.(35) The regasified natural gas

is generally fed into pipelines for distribution to consumers. However, if the regasified natural gas is intended to be transported or otherwise used as LNG (e.g., in LNG vehicles), it would need to undergo a second liquefaction step, which would substantially increase the fuel's carbon intensity value." This statement is incorrect as it relates to the Energia Costa Azul (ECA) LNG terminal. In the case of ECA, economics would likely dictate that imported LNG delivered as transportation fuel would simply be trucked to the distribution point from the receiving terminal. In addition, it is not currently possible to deliver ECA send-out gas to liquefiers in California because those liquefiers are not served by infrastructure that can receive ECA gas. (SEMPRA1)

Comment: Table IV-4 Fuel Pathways Under Development for Use in the LCFS. Sempra Energy does not believe the following two pathways are realistic and therefore they do not require evaluation at this time:

"Remote LNG shipped to Gulfport, Texas; regasified and pipelined to California and delivered as Compressed Natural Gas."

"Remote LNG shipped to Baja, CA; gasified and pipelined to California; liquefied in California for use as LNG."

We believe two additional pathways that do deserve further evaluation are:

Domestic natural gas delivered to California from the Rocky Mountain Region and delivered to Southern California utilizing a specific pipeline such as Kern River and liquefied for use as transportation fuel.

For imported natural gas (LNG) delivery of a 50/50 mix of Russian and Indonesia LNG delivered to the Energia Costa Azul (ECA) Terminal for regasification. The send-out gas will be delivered to California via the existing pipeline network in Mexico. (SEMPRA1)

Response: The NANG to LNG pathway document included both scenarios: LNG delivered to Baja, California (and Gulfport, Texas) which is then re-gasified and transported via pipelines and subsequently re-liquefied in California and LNG delivered to Baja and trucked as LNG to California without regasification. These pathways were created based on discussions with stakeholders. As for pathways that will be used in California, economics, natural gas supplies, LNG fleet penetration, etc. are some of the factors likely to dictate the demand for LNG as a transportation fuel. Stakeholders can use either one of the pathway carbon intensities published that represents their pathway.

As for the additional pathways being suggested, staff cannot realistically determine pathway intensities for all combinations of natural gas/liquefied natural gas likely to find use in California. The regulation includes in it Methods 2A and 2B to allow producers to

generate pathway carbon intensities that represent their pathways if the staff published pathways do not accurately represent their fuel carbon intensities.

K-139. Comment: Clarify to public stakeholders that domestic LNG does have significant GHG benefits and that LCFS diesel is not ready for market. (CE1)

Response: ARB staff has released a pathway document based on the best available operating performance data for LNG from domestic natural gas. That document clearly shows that domestic LNG can provide significant GHG benefits. Pathway documents have also been released for diesel blendstocks produced from UCO and tallow. These pathways will make the production of LCFS-compliant diesel possible. Larger volumes of compliant diesel will be needed as the regulatory carbon intensity ceiling declines, however. Given the incentives available to developers of lower-carbon blendstocks, there is a strong likelihood that those blendstocks will be available to fuel supplies in sufficient quantities to achieve compliance.

K-140. Comment: I want the low carbon fuel standard to be set so it takes into account the full carbon impact of fuels like corn ethanol and tar sands source. (SIERRACLB1)

Response: The LCFS fuel lifecycle analyses do account for all known, significant contributions to GHG emissions. How that accounting is accomplished is described in many of the responses to the comments in this Section (Section K, "Lifecycle Analysis"), and in Section L ("Land Use Change"). A pathway has not yet been established for tar sands but one will need to be developed before crude oil from this source can be refined in, or imported into, California.

K-141. Comment: In closing, we strongly encourage the ARB to continue to refine and improve its lifecycle modeling framework. We also believe the methodology and ARB's results must be further peer-reviewed by a multi-disciplinary group of disinterested economists, climate change scientists, soil scientists, plant biologists, and other experts. This has not yet been done. (ABENGOA)

Response: The ARB will continue to monitor information regarding fuel production and GHG emissions and will make adjustments when warranted. The Board has also directed staff to convene an Expert Workgroup to analyze and evaluate the land use change issues over which concerns have been raised by stakeholders. This group is to make recommendations to the Board by the end of 2010. Additionally, the Board approved LCFS requires mandatory program reviews in 2011 and 2014 which will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate. Please refer, also, to the response to comment L-7 in the Land Use Change section.

K-142. Comment: With the potential of CO₂ emission or fuel economy waivers being granted to California and the New England/Mid Atlantic States, there is the possibility of at least three different standards and, more important, three

different methods of calculating Green House Gas emissions. Therefore, it is important to have a single uniform method (or formula) for making these calculations. In establishing this formula, the following technical issues must be addressed.

a. A uniform standard for the conversion of CO₂ emissions from plug-in, electric only (see above) and conventional hybrids to miles per gallon (MPG) that is equal (not equivalent) to the MPG of internal combustion equipped vehicles. (Without this, marketing claims and false science will take over.)

b. A uniform standard (or algorithm) for the calculation of CO₂ emissions and MPG for biofuels, in addition to existing standards for corn-ethanol or soybean oil biodiesel, that can account for: a) increased energy content per gallon, b) decreased CO₂ emissions during fuel production, and c) increased MPG of new fuel mixtures. (Without this, significant regulatory barriers to the use of new biofuels, which would decrease CO₂ emissions without affecting food production and costs, would be created.) (ABUSA)

Response: ARB has been in communication with the New England/Mid-Atlantic states (as well as governmental entities) regarding the establishment of common methods for calculating fuel GHG emissions. ARB has provided a uniform standard for equating CO₂ emission from plug-in, electric-only, and conventional hybrids to corresponding internal combustion engines. The Board-approved LCFS also provides Energy Efficiency Ratio (EER) values to be used to adjust for efficiency differences between the various vehicle technologies. The inherently greater efficiency of battery-electric vehicles, for example, is accounted for through use of an EER value of 3.0. The reference EER for conventional gasoline vehicles is 1.0.

The energy content of fuels, and the GHG emissions associated with fuel production are accounted for in the CA-GREET model, which is used to calculate direct lifecycle emissions for LCFS-regulated fuels.

K-143. Comment: The report entitled “Detailed California-Modified GREET Pathway for Corn Ethanol” produced by Life Cycle Associates” for CARB does not meet acceptable scientific standards for a regulatory framework. All primary assumptions and data sources are not clearly documented, the analysis utilizes obscure and inconsistent units of measure, and results cannot be traced back to underpinning calculations. Underlying parameter values and data sources must be clearly shown according to ISO standards, EPA standards, and federal law. All calculations and data sources used should be documented in metric units in accordance with scientific standards. Life cycle assessment (LCA) methods that do not meet these standards will not be recognized by scientists, biofuel producers, or related industries. Transparent methodology is particularly important because the outcome of this LCA will likely exclude many biofuel producers from California markets. As the report is currently written, the disclosure of data sources and documentation for the proposed LCA are not

sufficient to allow rigorous scientific review. One key deficiency rests with the GREET model, which has been repeatedly changed and modified over the last 14 years such that data sources and documentation for the current version used in the proposed CARB Low Carbon Fuel Standard (LCFS) are scattered amongst a number of technical reports, most of which have not undergone peer review. Moreover, some of the parameter values used in the version of GREET have not been updated such that they are no longer representative of the systems evaluated. References and justification for the associated modifications of GREET parameters by Life Cycle Associates are also not documented. Specific points to support these conclusions follow, and we append a list of industry representatives who support the message conveyed to CARB in this document. (UNE1)

Comment: Primary Data Inputs for Corn-Ethanol LCA: As the draft report is written, the majority of primary data and the citations to support them are not clearly documented. Thus, the report fails to deliver the necessary information that allows rigorous scientific review. Incomplete documentation of assumptions and data sources is not an acceptable standard to facilitate disclosure and clarity for regulatory purposes, and it does not meet publishable scientific standards. The EBAMM8 and BESS9 LCA models and associated documentation of primary data are examples of appropriate transparency and disclosure. Such clarity is essential for setting the Low Carbon Fuel Standard (LCFS) in California. Without corresponding citations, it is not clear that the values employed in the LCA are representative of the systems evaluated. An acceptable level of documentation requires the exact parameter values used (based on primary data) directly linked to their supporting citation(s). This requirement is especially important for those parameters that have a large influence on GHG emissions, such as crop yields, nitrogen fertilizer application rates, grain to ethanol conversion yields, and energy use at the biorefinery per unit of ethanol produced. Documentation for less sensitive parameters is also needed because although they may have relatively small impact on an individual basis, their combined effect on the LCA can be substantial. Conclusion: All values and corresponding units for primary data inputs used in the proposed LCA framework must be provided and clearly linked to the supporting documentation. Preference should be given to documentation taken from peer reviewed publications or other widely accessible databases. (UNE1)

Comment: The transparency of underpinning assumptions and data sources used in the corn-ethanol LCA analysis performed by Life Cycle Associates for CARB's LCFS does not meet minimal standards to enable scientific review of the proposed LCA methods and GHG intensity values. The proposed CARB LCFS for corn ethanol likewise does not meet ISO, EPA, or U.S. legal standards for clarity, documentation, and completeness of data and assumptions of models used in a regulatory framework. The enormous complexity of biofuel LCA analysis requires: (1) detailed description of the parameters used in the LCA method and their supporting references, (2) use of parameters that are

consistent with the source documentation, and (3) metric units in accordance with other scientific and regulatory frameworks. (UNE1)

Comment: The current draft of CARB’s “Detailed California-Modified GREET Pathway for Corn Ethanol” does not include sufficient qualifying information required under ISO guidelines listed above for LCAs. The draft also provides insufficient references to validate the source and quality of the data employed, as required by EPA guidelines and federal law discussed above. Although the GREET model website was given as one of the few references in the report, documentation of the CARB-GREET model relies on a large number of informal, unrefereed reports that modify earlier versions of the GREET model and therefore do not serve to as adequate citation and justification for this report. Documentation for GREET also does not provide sufficient information about the changes made by Life Cycle Associates in producing the final LCA results shown in the CARB report. Therefore, the current draft version does not adequately support the findings of CARB that represent the foundation of its draft regulations for the LCFS20. (UNE1)

Comment: With the passage of section 515 of the Treasury and General Government Appropriations Act of 2001 (Public Law 106–554; H.R. 5658), government-wide guidelines for information quality were established. Associated guidelines from the Office of Management and Budget state:

“Agency guidelines need to achieve a high degree of transparency about data even when reproducibility is not required...The purpose of the reproducibility standard is to cultivate a consistent agency commitment to transparency about how analytic results are generated: the specific data used, the various assumptions employed, the specific analytic methods applied, and the statistical procedures employed...With regard to analytic results related [to influential scientific, financial, or statistical information], agency guidelines shall generally require sufficient transparency about data and methods that an independent reanalysis could be undertaken by a qualified member of the public...The primary benefit of public transparency is not necessarily that errors in analytic results will be detected, although error correction is clearly valuable. The more important benefit of transparency is that the public will be able to assess how much an agency’s analytic result hinges on the specific analytic choices made by the agency. Concreteness about analytic choices allows, for example, the implications of alternative technical choices to be readily assessed. This type of sensitivity analysis is widely regarded as an essential feature of high-quality analysis, yet sensitivity analysis cannot be undertaken by outside parties unless a high degree of transparency is achieved. The OMB guidelines do not compel such sensitivity analysis as a necessary dimension of quality, but the transparency achieved by reproducibility will allow the public to undertake sensitivity studies of interest.” (p. 8456) (UNE1)

Comment: GREET Scientific Units and Calculation Structure—Embedded

Assumptions: Many scientific units used in the GREET model, and described in the CARB report, are based on unconventional units that combine both English and metric measures. Examples of such units used in the CARB-GREET model include: nutrient inputs for crop production in grams per bushel (g/bu) and grams carbon dioxide equivalent per million British thermal units (gCO₂e/mmBtu). Reliance on such unconventional units reduces transparency of parameter values and does not contribute to full disclosure of data and methods employed. Metric units should be employed exclusively to correspond with scientific standards to be congruent with related international greenhouse gas (GHG) emission LCA standards under development. For example, although units of grain yield and fertilizer inputs to crops are reported by the US Department of Agriculture in English units (e.g. gal/ac or lb/ac), they should be transformed into metric units. (UNE1)

Comment: Calculations in the GREET model scale all crop inputs linearly to grain yield, with resulting intermediate parameters in British thermal units per bushel of grain (Btu/bu) and grams per bushel (g/bu); these units are presented as primary data in the CARB report, but they are actually integrative parameters that lack transparency as to the source of data. For example, the use of Btu/bu and grams/bu conflates reported energy and nutrient inputs per unit area for corn production (e.g. kg/ha, L/ha, kg/ha) with crop yield per unit area (Mg/ha), which results in spatial and temporal biases. Historically, nutrient use has also become more efficient and is not directly related to grain yield. Crop inputs per unit of grain yield vary substantially from state to state, with southern states requiring greater nutrient inputs per unit of grain produced, and western states requiring additional fossil fuel use for irrigation. As a result there is substantial spatial and temporal variability in net energy yields and GHG emissions for a given biofuel system that cannot be captured unless region- or state-specific values are used for inputs and outputs from the feedstock production system. Such regional analyses should use the most recent crop yields, nutrient input rates, and fossil fuel costs of energy and inputs used in all phases of the life cycle. Calculation of greenhouse gas emissions alone for LCFS implementation does not require estimation of criteria pollutant emissions (volatile organic carbon [VOC], and carbon monoxide [CO]). Inclusion of these calculations in the core of the calculation structure of GREET may introduce inaccuracy and is non-essential for the calculations required for a LCFS. (UNE1)

Comment: Denaturant Blending with Biofuels: Corn ethanol biorefineries produce ethanol as a primary product and are required to blend in a minimum amount of denaturant before shipping to the blender in accordance with liquor laws. Gasoline is used as the denaturant, and the level of denaturant added is highly variable. On average, Nebraska corn-ethanol plants in 2007 blended denaturant at 2.7% by volume based on data from the Nebraska Department of Environmental Quality (NDEQ); in 2005 and 2006 in NE, denaturant was blended at 4.1% and 4.3%, respectively. Ethanol can also be transported and used in

anhydrous form, as is done in Brazil. After transport, ethanol is blended with more gasoline to reach the desired ethanol blend concentration, roughly 10% (E10) or 85% (E85). We would argue that a comparison of blended products (gasoline containing ethanol, and ethanol containing gasoline) is biased against ethanol. The inclusion of denaturant in the emissions intensity of ethanol results in an inflated GHG intensity of the biofuel, while inclusion of ethanol in a gasoline blend reduces its emissions intensity. Because the denaturant does not reflect the inherent biofuel GHG contribution to global warming, it should be excluded from the life cycle calculation.

Regulations should compare the GHG emissions intensity of pure products based on their sources: 100% petroleum-based gasoline in the form of reformulated blendstock and 100% ethanol in anhydrous form. This is consistent with the recommendations of the Roundtable on Sustainable Biofuels, Version Zero13. We further argue that life cycle regulations, such as the CARB-LCFS should be based on straightforward methods, where gasoline and ethanol can be thought of as two buckets that pour into the state's fuel system. The level of denaturant blended with ethanol for transportation in California and other states should be considered part of petroleum imports, as the biofuel will be eventually further blended with petroleum before final use. The fraction that is denaturant should be subtracted from the ethanol volume, and considered a component of the state's gasoline imports. (UNE1)

Comment: Reporting of LCA Results: Final life cycle emissions from biofuels should be reported in an emissions inventory format. This format would show all emissions and enable clear inspection of the life cycle boundaries employed, the factors that contribute to each component of the life cycle, and the resulting final emissions estimates. Specifically, the individual emissions in the crop production system and the bio refinery system should be shown in a list (disaggregated) to provide a clear understanding of the results. The current CARB-GREET format documentation for corn-ethanol does not provide a complete emissions inventory, which makes it a "black box" for anyone that wishes to verify the components. (UNE1)

Comment: ISO standards specify the need for qualifying information to supplement data used in LCA. The standard states: "The data quality requirements should address:

- time-related coverage;
- geographical coverage;
- technology coverage;
- precision, completeness and representativeness of the data;
- consistency and reproducibility of the methods used throughout the LCA;
- sources of the data and their representativeness;
- uncertainty of the information."

EPA's guidelines for environmental model development and evaluation also emphasize the need for transparency: "In the course of modeling, many choices

must be made and options selected which may lead to biases in the model results. Documentation of this process and its limitations and uncertainties is essential to increasing the utility and acceptability of model outcomes. Modelers and project teams should document all relevant information about the model to the extent practicable, particularly when a controversial decision is involved.” (UNE1)

Comment: EPA’s Information Quality Guidelines further emphasize transparency with regard to data sources used to ensure high quality analysis:

“EPA recognizes that influential scientific, financial, or statistical information should be subject to a higher degree of quality (for example, transparency about data and methods) than information that may not have a clear and substantial impact on important public policies or private sector decisions. A higher degree of transparency about data and methods will facilitate the reproducibility of such information by qualified third parties, to an acceptable degree of imprecision...It is important that analytic results for influential information have a higher degree of transparency regarding (1) the source of the data used, (2) the various assumptions employed, (3) the analytic methods applied, and (4) the statistical procedures employed. It is also important that the degree of rigor with which each of these factors is presented and discussed be scaled as appropriate, and that all factors be presented and discussed” (p.20). As a complement to the EPA Information Quality Guidelines, the EPA Science Policy Council emphasizes general transparency as the third of a number of assessment factors:

“Clarity and Completeness - The degree of clarity and completeness with which the data, assumptions, methods, quality assurance, sponsoring organizations and analyses employed to generate the information are documented.” (UNE1)

Comment: The current draft of CARB’s “Detailed California-Modified GREET Pathway for Corn Ethanol” does not include sufficient qualifying information required under ISO guidelines listed above for LCAs. The draft also provides insufficient references to validate the source and quality of the data employed, as required by EPA guidelines and federal law discussed above. Although the GREET model website was given as one of the few references in the report, documentation of the CARB-GREET model relies on a large number of informal, un-referenced reports that modify earlier versions of the GREET model and therefore do not serve to as adequate citation and justification for this report. Documentation for GREET also does not provide sufficient information about the changes made by Life Cycle Associates in producing the final LCA results shown in the CARB report. Therefore, the current draft version does not adequately support the findings of CARB that represent the foundation of its draft regulations for the LCFS (UNE1)

Comment: The transparency of underpinning assumptions and data sources used in the corn-ethanol LCA analysis performed by Life Cycle Associates for CARB’s

LCFS does not meet minimal standards to enable scientific review of the proposed LCA methods and GHG intensity values. The proposed CARB LCFS for corn-ethanol likewise does not meet ISO, EPA, or U.S. legal standards for clarity, documentation, and completeness of data and assumptions of models used in a regulatory framework. The enormous complexity of biofuel LCA analysis requires: (1) detailed description of the parameters used in the LCA method and their supporting references, (2) use of parameters that are consistent with the source documentation, and (3) metric units in accordance with other scientific and regulatory frameworks. The current document provided by CARB fails to meet these requirements and, therefore, does not provide the foundation for effective regulation. (UNE1)

Response: The basis of the fuel lifecycle analyses performed for the LCFS is the Argonne National Laboratory's GREET model. This model was modified to include California specific factors, such as efficiency factors and fuel use data specific to California electrical generation utilities. All of the inputs for the GREET model are supported with appropriate documentation. Argonne's documentation consists of the papers, reports, and journal articles that served as the sources of the data contained in the model. For each of the fuel pathways that was characterized using the GREET model, a detailed documentation report was prepared. Each report provides detailed accounts of the methodologies, inputs, calculations, and references used in the development of the pathway. ARB held a number of public workshops in which the details of the modeling and background analyses were discussed, and sponsored two GREET training courses in which stakeholders learned how to use the GREET model. The GREET model has long been available to the public as a free download on the ARB website. While the documentation for GREET is contained in a series of publications, the level of detail is comparable to the Biofuel Energy Systems Simulator (BESS) and EBAMM. Both BESS and GREET contain corn farming data. When identical inputs are supplied to both models, BESS and GREET provide virtually identical results for corn production. The data and units used for corn production in CA-GREET are based on and consistent with widely used U.S. Government statistics. Although these data are not peer reviewed, they are generally regarded as best available aggregate information on corn farming inputs. Importantly, BESS can only be used for ethanol production from corn, while GREET can be used for all fuels regulated under the LCFS.

The units reported in the LCFS documentation are the same as those used in the GREET model and in the model's documentation. The GREET model uses the units of commerce (gallons, bushels, BTUs, etc.) with which LCFS stakeholders are familiar. The inputs to the model are well-reviewed; converting the analysis to SI units would not improve the model's transparency, as the unit conversions are straightforward. Likewise, documenting model inputs primarily in SI units (despite the model's use of units of commerce) would, if anything, compromise transparency. The energy inputs in the GREET model were recently revised by Argonne to include the most recent USDA data. The LCFS CA-GREET analysis does not rely on the future scaled up projections in GREET.

Importing denaturant for ethanol is an activity that is associated with ethanol infrastructure, not gasoline. Denaturant travels along with ethanol through the transportation and distribution infrastructure. This infrastructure includes rail transport (in the Midwest), transport by heavy duty truck to blending terminals, and heavy duty truck transport to refueling stations. This distribution system is quite different from the system used for gasoline. Ultimately, the carbon intensity of California reformulated gasoline (RFG) is calculated using the actual quantity of ethanol that is blended with CARBOB. For example, 10.5 percent denatured ethanol, by volume, is required to produce a blended RFG with 10 percent ethanol. The CI for the resultant gasoline would reflect the volume-based 10 percent ethanol content of the finished fuel. Ethanol imported into California, and ethanol produced in-state has generally been blended with a denaturant that is reasonably close to a consistent value. The variation has not been great enough to justify accounting for differing denaturant concentrations.

The GREET model is a transparent, widely used fuel life cycle model. The inputs to the model are based on a series of papers and reports available through Argonne National Laboratory. Updates of key inputs such as the farming energy for corn are also documented and published by Argonne. Changes made to the default GREET version 1.8b by Lifecycle Associates are listed in the “Modifications” sheet of the CA-GREET model, and all key inputs for the transportation fuels analyzed for the LCFS are documented in ARB’s fuel pathway documents, which are available online.

The successful implementation of the LCFS depends upon the development of defensible carbon intensity analyses for regulated fuels. As part of the scenario analysis, however, ARB staff has also calculated the impact of the regulation on the State emissions inventory (in units of tons per day). The role of the scenario analyses are described in Section VI of the ISOR.

Staff has adhered to ISO and U.S. EPA guidelines in the performance of its lifecycle analyses to the extent possible. One critical criterion is transparency and both the model and pathway documents (and updates) have been made available and are transparent. Comprehensive discussions of most of the data sources and calculations used in the GREET model can be found on the Argonne web site. The California data in CA-GREET has been extracted from the California emission inventory, Energy Commission databases, industry surveys, etc.

K-144. Comment: A brief review of the collected documents shows very clearly that the calculations used to determine the relative “carbon intensities” of the energy sources are not in fact based on empirical data sets or well-documented and tested models. (ABCINC)

Response: The models used to calculate carbon intensities were developed by Argonne National Laboratory (GREET) and Purdue University (GTAP) and are widely accepted, well documented, and peer-reviewed. ARB has been very transparent regarding the development of fuel pathways. Numerous public workshops have been

conducted where the details of the analyses have been provided for public review and comment. The details were also made available as part of either the first or second 15-Day public comment period. For more information on modeling direct lifecycle emissions and modeling land use change impacts, see Chapter IV of the ISOR.

K-145. Comment: The significant figures used in the analyses to determine the carbon intensities of various fuels are inconsistent as shown in public documents. The number of significant figures can result in important implementation/compliance results and must be corrected. This comment is consistent with comments from various peer reviewers. (CONOCO)

Response: The number of significant figures used in LCFS carbon intensity calculations is determined by the LCFS compliance schedule and the modeling methodology used, and cannot be avoided. Although the use of two significant figures would have been more consistent with known uncertainty levels, four were sometimes necessary if fuel carbon intensities were to be meaningfully compared to the LCFS compliance schedule. In the compliance schedule, the incremental carbon intensity reductions for gasoline and diesel fuels are so small during the initial years that four significant digits are necessary to quantify the reductions. In 2011, for example, the carbon intensity of diesel fuel reduces 0.25 percent dropping from 94.71 to 94.47 g/CO₂e/MJ, a change of only 0.236 g/CO₂e/MJ. With two significant digits, reductions would have to be nearly one percent to be quantifiable. Significant figures are also discussed in Appendix A of the ISOR.

K-146. Comment: WSPA is very concerned and confused by this new addition to the regulation. We believe it is premature to presume the fuels listed will have a full fuel-cycle carbon intensity that meets the compliance schedules through 2020. This does not portray a purported equal or fuel neutral treatment by ARB. In other sections ARB works to ensure the market for LCFS credits will not be manipulated by traders and other non-obligated parties. Why is ARB treating electricity generators differently than other parties? (WSPA)

Response: ARB lifecycle analysis results, as adjusted to reflect vehicle energy economy ratios (EERs) has identified a group of fuels with carbon intensities low enough to achieve full LCFS compliance as they currently exist. Electricity is one such fuel. Because these fuels have achieved compliance before the fact, the Board determined that it would be pointless to require the providers of those fuels to observe LCFS reporting requirements. Providers of these fuels may opt-in, however, if they would like to earn credits. Opting in triggers the same set of reporting requirements to which all regulated fuels are subject.

K-147. Comment: ARB should consider adopting a registration program for producers of renewable fuel similar to the registration program under § 80.1150 of the Federal RFS program. An element of the registration would be certification of the carbon intensity of the fuel produced at the production facility and the physical pathway for that facility. (WSPA1)

Response: Although the LCFS does not include a fuel registration requirement similar to the Federal Renewable Identification Number (RIN) program, regulated parties will be required to register, and to report their fuel carbon intensities using a web-based reporting system. Physical fuel pathways must also be reported via this system.

K-148. Comment: For the hydrogen pathway, the draft does not address the issue of steam production and how it might be credited. Large central hydrogen facilities can utilize by-product steam and receive credit, whereas on-site (local) hydrogen production might not. Steam utilization directly impacts the process efficiency, hence the carbon intensity values for hydrogen production. Typically, steam methane reformers utilize steam by-product which would have an energy efficiency around 70% (a value close to 60% should be used for processes that could not utilize the steam by-product). Such differentiations are critical and should be stated in the pathway document. (CONOCO)

Response: The current LCFS hydrogen pathway was calculated using average process and efficiency data. Providers of lower-carbon hydrogen fuel may apply to the Board for the establishment of new hydrogen sub-pathway that better reflects their fuel's carbon intensity. The application process is described in the Method 2A provisions of the LCFS regulation (see §95486).

K-149. Comment: Various typographical errors were observed between the numbers and the formulas listed in various spreadsheets compared to the write-ups presented in text format. These errors must be corrected. (CONOCO)

Response: It is staff's intent to correct these in an errata.

K-150. Comment: Thus, it is critical that CARB approach this rulemaking with the utmost care, open mindedness, and flexibility. To deliver the maximum real GHG reductions, CARB's computation of lifecycle GHG profiles must: (1) follow consistently applied and thoroughly vetted methodology; (2) be based on contemporary and complete data; and (3) account for and encourage a range of future technology advances to ensure continued reductions in the carbon intensity of the state's fuel mix. BIO believes that CARB's approach fails at least partially in each of these areas. (BIO)

Response: In using the CA-GREET and GTAP models, ARB is using consistently applied and thoroughly vetted methodologies which are based on contemporary and complete data. ARB will continue to monitor developments in fuel production and make changes to the fuel carbon intensities when appropriate. Regulated parties wishing to add fuel pathways that better reflect the carbon intensities of their fuels may do so under the Method 2A and 2B provisions of the regulation. These provisions are designed to encourage existing producers that utilize higher efficiency processes or the producers of next generation low carbon fuels to enter the LCFS-regulated fuel market. It should also be noted that the Board directed staff to convene an Expert Workgroup to evaluate and recommend improvements to the land use change modeling approach

currently in use. Recommendations are to be presented to the Board by December 2010. For more information on the Board's approach to modeling direct lifecycle emissions and for modeling land use change impacts, see Chapter IV of the ISOR.

K-151. Comment: As a general approach, we have recommended and continue to recommend that each fuel, crude, ethanol based, electric vehicle... be subject to its own individual pathway assessment. However, in practice, there may be benefits for administrative simplicity of having all crude oils assigned one value. Regardless, any LCFS policy must be based on sound science, and be open and transparent. (AE1)

Response: ARB has established fuel pathways which cover the majority of fuel production scenarios. For crude oil, except for high carbon intensity crudes not used in California in 2006, ARB has assigned one value taking into account the 2006 California crude mix as reported by the California Energy Commission. The analysis presented in the ISOR and approved by the Board was based on the best available data on the practices used to produce feedstocks and finished fuel, as described in the fuel pathway documents available on the LCFS web site. The information used and the methods applied were presented at several workshops. Staff solicited and received a large volume of comments from participating stakeholders. Where appropriate, staff revised the published pathway information to reflect the technically sound comments received. The indirect Land Use Change analysis utilized a peer-reviewed, publicly available model. As a result, the fuel pathways and carbon intensity values the Board has released are scientifically defensible, and sufficiently robust to serve as the basis for the LCFS. In order to address some of the remaining uncertainty in those carbon intensity values, the Board directed staff to convene an Expert Workgroup to help refine and improve current land use change estimates. Recommendations from this group are required by December 2010. Additionally, there are two mandated reviews in 2011 and 2014 when additional refinements could be considered.

K-152. Comment: Executive Order S-O1-07 directs ARB to measure the LCFS on "a full fuels cycle basis" to "reduce emissions of greenhouse gases, criteria pollutants, and toxic air contaminants," and it is of critical importance to not ignore known contributions of GWI along a particular fuel's lifecycle. To ignore values will artificially deflate the fuel's overall GWI, thus obstructing the realization of actual GHG reductions. We recommend overestimating emissions contributions in times of scientific or pathway uncertainty. (CERA2)

Response: If the LCFS is succeed in achieving a significant reduction in fuel carbon intensity, all fuel carbon intensities must be subject to the same carbon intensity determination process. Unless fuels are treated fairly and impartially, and unless all carbon intensities are calculated similarly, the measurement of fuel carbon intensity, and the comparison of those measurements to annual standards, will have little or no meaning. Before California can claim it has reduced fuel carbon intensity, the methods it uses to measure that quantity must be technically sound, scientifically defensible, and impartial. Applying carbon intensity determination methods impartially will also improve regulated party buy-in making the program simpler to administer. In the interest of

obtaining the most accurate values for fuel carbon intensities, ARB uses the most accurate data available, along with well documented and peer reviewed models (CA-GREET and GTAP) to calculate carbon intensities. All pathway assessments are made available for public comment. Additional pathways will be established via the open, and public California regulatory process..

K-153. Comment: Please remember that there are lots of Petro Industry dollars being spent to discredit the biofuel production. Please reread the recent Yale paper that put the above number in a place I hope you will remember when you adopt any new standard for "low" carbon. (UCSB)

Response: The Board estimated the carbon intensity of all fuels to be regulated under the LCFS using the best available information and analytical tools, and then released the results for extensive public comment. Staff evaluated all comments received equally, and revised its analysis to reflect all comments that raised verifiable substantive issues affecting its published carbon intensity estimates. The only criterion staff considered in evaluating the comments it received was the scientific defensibility of the information provided. The process was open and objective, and, as a result, has produced technically sound and well-vetted carbon intensity values. These values will continue to be evaluated by an Expert Workgroup to be convened in response to Board Directives contained in Resolution 09-31.

K-154. Comment: Reducing carbon emissions in transportation fuel, a subject of recent national debate, is in fact an ambitious and admirable goal for the state of California. It is also a goal fraught with danger. Unless sound, proven science is used to determine carbon emissions, the state and nation could suffer the reverse effect: a transportation system that actually increases emissions. (GE3)

Response: The analysis presented in the ISOR and approved by the Board was based on the best available data on the practices used to produce feedstock and finished fuel, as described in the fuel pathway documents available on the LCFS web site. The information used and the methods applied were presented at several workshops. Staff solicited and received a large volume of comments from participating stakeholders. Where appropriate, staff revised the published pathway information to reflect the technically sound comments received. The indirect Land Use Change analysis utilized a peer-reviewed, publicly available model. As a result, the fuel pathways and carbon intensity values the Board has released are scientifically defensible, and sufficiently robust to serve as the basis for the LCFS. In order to address some of the remaining uncertainty in those carbon intensity values, the Board directed staff to convene an Expert Workgroup to help refine and improve current land use change estimates. Recommendations from this group are required by December 2010. Additionally, there are two mandated reviews in 2011 and 2014 when additional refinements could be considered.

K-155. Comment: We support the complete lifecycle and pathways analysis so as to promote production and consumption of biofuels from local sources whenever

possible. While California has a low potential for native oilseed crops, it offers a substantial resource in the form of waste oil. (SFB2)

Response: This comment was inadvertently duplicated. See response to Comment K-176.

K-156. Comments: It has been reported that about one-half of the oil used in California is imported from nations such as Saudi Arabia, Iraq, and Columbia. These sources of oil have both direct and indirect effects that CARB inexplicably has chosen to ignore in its modeling to determine the carbon intensity of petroleum. It has been pointed out that the direct effects include pumping seawater into the oil wells of Saudi Arabia to increase pressure and powering shipping vessels during transport of Middle East oil to the U.S. These are summarized as:

- Half of the oil used in California is from Middle Eastern countries, but CARB ignored the associated GHG emissions (such as the emissions from tanker transport to the U.S. and California) (ACE);
- Figure S-1 from the 2009 Lifecycle Associates study, shows that production of petroleum fuels involves numerous energy and economic impacts that affect the global GHG emissions associated with fuel consumption. Many of the impacts of oil production are examined in well published fuel life cycle studies, which primarily use average energy inputs and emissions. However, a variety of emissions sources associated with petroleum production are often omitted from life cycle studies. (ACE)
- There are several problems with the treatment of petroleum under the draft LCFS rule. We are concerned that the treatment of petroleum will result in increased dependence on increasingly carbon intensive petroleum fuels in the near term. (NFA)
- To illustrate the point, the ISOR contains only three fuel pathways for petroleum, but has identified 12 pathways for ethanol alone. Clearly petroleum has more than three pathways, yet the ISOR essentially treats petroleum as if it is generic. Again, this creates an opportunity for the baseline "California average petroleum" carbon intensity to act as a safe haven for an increasingly carbon intensive petroleum product. (NFA)

Response: The LCFS establishes an average value for all crudes used in California refineries and that includes imported crudes. The CA-GREET model accounts for the crude transported from the Middle East to the U.S. and to California in the inputs and also considered the GHG emissions from crude recovery. The LCFS uses one pathway to characterize average crude produced from average refining processes, but uses that pathway to calculate individual carbon intensity values for the two baseline fuels, gasoline and diesel. The Board found that the overriding consideration in specifying average values for refineries is the preservation of fuel fungibility. If transport distances, energy efficiency values, and emission rates varied by refinery or crude type, the fuels produced by those refineries would have to be separately tracked through the

distribution network, sacrificing fungibility. Moreover, the regulations implementing California Global Warming Solutions Act of 2006 (AB 32) are likely to bring the State's refineries into conformance with average California specifications.

High-carbon-intensity crudes, such as those from Canadian oil sands, will be evaluated separately, however, and will receive carbon intensity values that reflect their specific production circumstances.

The large number of pathways for ethanol was created to accommodate the variability in the production of ethanol and to provide flexibility to ethanol producers. As discussed in the ISOR we expect that LCFS will decrease the consumption of petroleum products and increase the consumption of lower-carbon fuels, including biofuels.

The Lifecycle Associates study cited in this comment concluded that the indirect effects associated with petroleum production are not significant. Staff to continue examine the direct and indirect GHG emissions of LCFS-regulated fuels, including petroleum. Indirect effects, in particular, will be focus of an expert workgroup to be convened in keeping with Board directives contained in Resolution 09-31.

K-157.Comment: As depicted in Figure S-1, production of petroleum fuels involves numerous energy and economic impacts that affect the global GHG emissions associated with fuel consumption. Many of the impacts of oil production are examined in well published fuel life cycle studies, which primarily use average energy inputs and emissions. However, the variety of emission sources associated with petroleum production is often omitted from life cycle studies. The GHG emissions associated with the production and use of petroleum fuels are still uncertain, particularly for fuels on the margin. The supply chain requires additional study as many of the methods used to estimate GHG emissions are still poorly developed. However, co-products and heavy refining do account for high outputs as can be seen in the case of Venezuela Heavy Crude. This is also apparent as a result of increased venting and flaring in Nigeria, the protection of oil in Iraq and the production of Canadian oil sands. Calculations in this study indicate that the fate of residual oil and petroleum coke is important, and a potentially significant source of GHG emissions, but require further economic modeling. The magnitude of carbon emissions associated with these products indicates that a detailed analysis of their fate and the effect on other fuel markets should be examined. The definition of a direct vs. indirect effect may remain vague. The debate as to whether the Iraq war, for example, is an effect that occurs as a direct or indirect result of petroleum dependence will continue. It could be argued that an indirect effect of the war, and therefore petroleum use, might include health effects and long term Middle East presence by the western world. Nonetheless, the magnitude of the emissions directly associated with military activity is readily calculated. More analysis may improve the readers' perspective but opinions are likely to remain diverse. Higher oil prices and dwindling light crude stocks induce development of more costly, energy intensive

petroleum resources that have higher than average life cycle GHG emissions. These marginal supplies are associated with:

- Tertiary oil recovery
- Production of heavy oils
- Production of oil sands derived fuel
- Imports of finished product from remote locations in relatively small vessels
- Production from small capacity stripper wells

Once projects are completed and operational the oil produced becomes part of the world oil supply. Hence, the average GHG emissions are expected to increase and new marginal supplies are likely to have even higher greenhouse emissions. Nonetheless, high cost, energy intensive marginal resources must be factored into current and future projections of the impact of petroleum based transportation fuels to the extent that marginal considerations are taken into account for alternative fuels. (ACE)

Response: These are issues dealing with high carbon intensity crude, which are addressed in response to Comments K-156 and C-220 through C-262.

K-158. Comment: Calculations used to determine the relative “carbon intensities” of the energy sources are not in fact based on empirical data sets or well-documented and tested models. (ABCINC, GE3)

Response: The values used in the CA-GREET model are based on data published by entities such as the USDA, U. S. EPA, etc. The CA-GREET model is a publicly available, well documented model that has been peer-reviewed. The rationale for selection of this model for the analysis of direct effects was discussed over several workshops during the early stages of the LCFS regulatory process. All inputs, assumptions, parameters used in the analysis for all fuel pathways have been published in the pathway documents. Comments were solicited from stakeholders and appropriate refinements made where appropriate. The land use change analysis was conducted using again a peer-reviewed, well documented, publicly available model. Updates to analysis was also considered based on comments received and these were included as part of the ISOR. We believe that we have the most accurate representation of fuel pathways at the present time with currently available data. The Board in approving the ISOR directed staff to establish an Expert Workgroup to further refine the current analysis and make recommendations which will be considered by the Board in December 2010. There also are two mandatory program reviews in 2011 and 2014 when refinements could be considered if appropriate based on available data at that time.

K-159. Comment: In the case of energy efficiency in ethanol production, the 2009 IEA Report has documented an experience curve that shows corn yields have increased by 0.113 tons/ha/year and nitrogen requirements have decreased at the rate of 0.10 kg N/ton/year, based on fifty year trends. The CA-GREET model

assumes a static value for direct land-use emissions. As with the other parameters, there is no adjustment factor for future improvements in land use and Method 2A of the Proposed Regulations does not expressly authorize the use of industry-wide data on land use to supplant the data inputs in CA-GREET. (NOVOZYM1)

Comment: The current analysis failed to account for GHG emissions in the following areas:

- a. Refineries now rely on coal rather than gas or oil for energy. Coal has the highest carbon content (25.4 tonnes of carbon per terajoule compared to 19.9 tonnes per TJ for mineral oil).
- b. Most ethanol plants have traditionally used natural gas to power their operations, but as this becomes more expensive, some are switching to coal
- c. Modeling must account for the extraction, production and distribution of natural gas when calculating GHG emissions; not just power plant emissions. (CERA2)

Response: The CA-GREET model was used for calculating carbon intensity values of all transportation fuels and is based on the GREET model that was developed by Argonne National Laboratory, which periodically updates this model. These past updates have been considered in the CA-GREET model, and, where relevant, adopted for the California model. The data inputs for the GREET model are presented in several technical documents that are available through Argonne National Laboratory. Both the CA-GREET and the Argonne GREET are well documented. The IEA analysis that indicates increases in yield and changes in nitrogen requirements were not used in the LCFS analysis. Instead USDA data was used and is the most current data available. When new data becomes available and represent industry wide practices, the data can be evaluated during the periodic reviews in 2011 and 2014 that the Board has mandated and be used to refine the analysis. Methods 2A and 2B provide additional flexibility for individual producers when there are data to support the development of a specific pathway for their fuel.

Currently California biorefineries do not use coal in their operation, and ARB does not expect coal use in in-state refineries in the future due to cost and regulatory requirements. There is a pathway presented in the Lookup Table that considers 100 percent coal use by an ethanol plant operating in the Mid-west. If such a plant provides ethanol to California, it will be required to use the designated pathway or develop an alternate pathway via Method 2A. The Well-to-Wheel analysis for natural gas used as process fuel does include GHG emissions from the extraction, processing and transportation and not just when used as fuel in a power plant.

The CA-GREET model accounts for all of the GHG emissions for the fuel pathways included in the regulation. Criteria pollutants and toxics for plants in California are expected to be mitigated (e.g. offsets) as part of the permitting process for siting such

facilities in California. Staff is also working on a siting guidance document for biorefineries in California.

K-160. Comment: The energy efficiency of ethanol plants has been specified in the CA-GREET model using fixed historical data, without adjustment for efficiency improvements. The 2009 IEA Report documents how "energy efficiency at ethanol plants has increased steadily over time. This has also been empirically documented by Adam Liska et al. in *Improvement in Life Cycle Energy Efficiency and Greenhouse Gas Emissions of Corn-Ethanol* (Yale, 2008). The IEA Report found that energy requirements for ethanol have been reduced by 16% for each doubling of production.¹⁹ The IEA Report documents an "experience curve" from which further gains in refinery energy efficiency can be reasonably expected and calculated through extrapolation.²⁰ The Staff Report Lookup Tables are based on historic data (which in some cases were extrapolated to 2007 from 2001 data), without adjustment for reasonably expected efficiency gains that will occur continuously in the future. This static approach biases the calculation of carbon intensity values for corn-based ethanol and should be corrected by staff. (NOVOZYM1)

Comment: The CA-GREET model also includes a parameter for direct land-use carbon emissions attributable to N₂O releases incident to tilling the soil and the use of fertilizer. The 2009 IEA Report documents that a "significant portion of the GHG emissions in the ethanol lifecycle arises from the category of land use emissions. The methods for calculating N₂O emission factors are complex and dependent upon modeling assumptions. The IEA Report shows how improvements in tillage practices or fertilizer applications could have significant effects upon calculated direct land-use emissions.²⁸ The CA-GREET model assumes a static value for direct land-use emissions. (NOVOZYM1)

Comment: In summary, the Board should consider directing staff to incorporate dynamic improvements in many land-use variables, as well as revising Method 2A to allow modification of the Lookup Table values. Novozymes has not attempted to identify all of the parameters and variables of the CA-GREET and GTAP modeling that should be revised to reflect continuous improvements and changes in land use and in ethanol production. Novozymes recommends the Board consider the treatment of the many issues identified in other scientific studies submitted to the staff, including the memorandum of February 27 from Liska and Cassmann, et al., and comments filed on behalf of UNICA (with special reference to the dynamic changes in Brazilian land use that are not captured in the Staff Report), RFA and Growth Energy. Incorporating experience curves that annually revise input values will provide a more realistic measure of the carbon intensity of the dynamic ethanol industry. (NOVOZYM1)

Response: The CA-GREET model used to calculate LCFS carbon intensity values is based on the GREET model, developed by Argonne National Laboratory. Argonne periodically updates the model. Updates are evaluated for inclusion in the CA-GREET

model, and are added when found to be appropriate. Both the CA-GREET and the Argonne GREET are well documented. The data inputs for the GREET model are described in several technical documents maintained by Argonne National Laboratory, and available on the Argonne web site. When new data that adequately represents industry-wide practices becomes available it can be evaluated during the periodic LCFS program reviews that the Board has mandated. Based on the results of these evaluations, the model can be updated. The LCFS provides fuel suppliers with an additional mechanism for updating the LCFS Lookup Tables: Methods 2A and 2B, which can be used to apply to the Board for the establishment of additional fuel pathways and sub-pathways.

K-161. Comment: Adjust baseline case for marginal gasoline source. The LCFS requires the Board to achieve annual reductions in carbon intensity measured against a baseline or reference scenario in which there is continued reliance on gasoline and diesel fuels. The Staff Report calculated the carbon intensity of California gasoline (CARBOB) based on the carbon intensity of the average rather than the marginal source of crude oil delivered to California refineries. The Staff Report's reliance on the average carbon intensity of delivered crude oil stocks masks market mediated impacts. That is, in the current market, marginal crude oil supplies are being obtained from sources like shale and tar sands in Canada. Such supplies have much heavier carbon intensity than other supplies of crude oil delivered to California. Novozymes believes that the LCFS reference case should be based on the carbon intensity of the marginal supplies of oil that would be displaced by the LCFS policies mandating lower carbon fuels. The size of California's oil market is sufficiently large that the LCFS, when implemented, should have a depressive effect on crude oil prices in California and world-wide. This should have the marginal effect of displacing the most expensive sources of crude oil, which may happen to be carbon-heavy tar sands from Canada. (NOVOZYM1)

Response: California Executive Order S-01-07 set the goal of a 10 percent reduction in the carbon intensity of transportation fuels used in California with reference to a 2006 carbon intensity baseline. The baseline, by definition, must reflect average 2006 fuel carbon intensities in the State. Average fuel CIs are calculated from the average crude mix. Once this baseline is established, it is locked in for the duration of the regulation. A new baseline is not recalculated annually. The annual carbon intensity ceilings established under the regulation are straight percentage reductions from the 2006 baseline. The marginal carbon intensity of crude is not relevant to establishment or application of the baseline. As this comment recognizes, the same average carbon intensities used to establish the baseline are to be used to determine annual compliance with the regulation: there is no requirement for providers of fuels based on or containing petroleum to account for an increase in the marginal carbon intensity of the crude used to refine their fuels. Although the Board currently has no firm projections concerning trends in the carbon intensity of the marginal crudes used to refine California fuels, this issue is one that stakeholders could propose for consideration at one or both of the program reviews that the Board mandated for 2011 and 2014. The Expert

Workgroup required to be convened by Resolution 09-31 to evaluate land-use change modeling, including effects of fuels other than biofuels, could also consider this.

K-162. Comment: The Staff Report calculated the carbon intensity of California gasoline (CARBOB) based on the carbon intensity of the average rather than the marginal source of crude oil delivered to California refineries. It used an assumption that crude oil recovered in California represented 40 percent of all crude delivered to California refineries. The Staff Report's reliance on the average carbon intensity of delivered crude oil stocks masks market mediated impacts. That is, in the current market, marginal crude oil supplies are being obtained from sources like shale and tar sands in Canada. Such supplies have much heavier carbon intensity than other supplies of crude oil delivered to California. (NOVOZYM1)

Response: See the response to Comment K-161 for additional details.

K-163. Comment: The Staff Report Lookup Tables are based on historic data (which in some cases were extrapolated to 2007 from 2001 data), without adjustment for reasonably expected efficiency gains that will occur continuously in the future. This static approach biases the calculation of carbon intensity values for corn-based ethanol and should be corrected by staff.

Response: The Board agrees that crop yields are likely increase in the future and that this will reduce the land use change impact of using crop-based feedstocks for biofuel production. For a discussion of how the Board handles yield increases, please see the section entitled, "Crop Yields, Production Yields, Agricultural Intensification" in Section L of this FSOR. However, our lifecycle assessments are designed to reflect current technology and agricultural practices and are not meant to predict future technologies or practices. As production technologies and agricultural practices evolve over time, the fuel lifecycle assessments will be periodically updated to reflect these changes. The two program reviews mandated by the Board in 2011 and 2014 will help allow this.

K-164. Comment: Based on these concerns and other considerations, we would urge that the Board amend the proposed LCFS regulation to assign the same carbon intensity to all mainstream crude oil fuel pathways from light to heavy crudes, including oil sands crude, rather than only the crudes in the baseline -- the, quote, baseline crudes mix. Now, these crudes all have similar life cycle intensities within a narrow and continuous range. And most of their life cycle emissions occur at the end -- at the burning phase of the cycle of the stage. (GOVTCANADA2)

Response: The carbon intensities of all regulated petroleum-based fuels are currently based on a single average crude carbon intensity—the same used to establish baseline fuel carbon intensities. Available data on trends in crude characteristics suggests, however, that it may not be appropriate to apply the 2006 average crude carbon intensity to all crudes that will used to refine fuels for the California market for the duration of the LCFS. For this reason, the Board will be evaluating the likely future

composition of the California crude mix. Fuels found to be refined from crudes with carbon intensities significantly higher than the 2006 average will have carbon intensity values that reflect that reliance on higher-carbon crude oil. The average crude carbon intensity should only be used to determine the carbon intensities of fuels refined from average crudes. The average crude carbon intensity shouldn't become a default value that providers of significantly higher carbon fuels are able to use when preparing their periodic LCFS reports. This approach also provides incentives for producers of potentially high carbon intensity crude oil to adopt innovative production methods to reduce greenhouse gas emissions.

With regard to the carbon intensities of crude sources, we do not agree that all mainstream crude oil production methods have similar carbon intensities. Our calculations show that carbon intensities for mainstream crude oil production methods range from about 4 to more than 20 gCO₂e/MJ. Requiring all crude sources not part of the 2006 baseline mix to be evaluated individually will help to ensure that increased use of "high carbon intensity crude oil" production methods are accurately reflected in the periodic reports fuel providers file with ARB under the reporting provisions of the LCFS. It will also provide a greater incentive for producers of these crudes to reduce emissions through Carbon Capture and Sequestration (CCS) or other methods.

See also response to Comments K-156 and C-220 through C-262.

K-165. Comment: Refinery efficiency as established in the LCFS is not correct and unfairly punishes less complex refiners. The starting point used by the GREET model developers (Michael Wang et al, Argonne National Laboratory) to determine refinery process CO₂ emissions the model assigns to CARBOB and CARB diesel is based on an estimate of the overall efficiency of the average refinery. The process used is described in the document, "Estimation of Energy Efficiencies of U.S. Petroleum Refineries" http://www.transportation.anl.gov/modelin/simulation/GREET/pdfs/energy_eff_petroleum_refineries-OS-08.pdf. There is currently very little public information regarding the efficiencies of individual refineries. The Argonne methodology uses Energy Information Administration (EIA) public data aggregated to a regional or national level. There are two weaknesses to this methodology that create obvious uncertainty in CARB's proposed carbon intensity baselines for CARBOB and CARB diesel to the LCFS. As the document referenced above states, the EIA does not survey refiners for hydrogen use or natural gas use for captive hydrogen production. Argonne used an estimate of refinery hydrogen useage from the SRI Consulting Chemical Economics Handbook. The method also requires estimates of the average energy content for each refinery feedstock and product listed in the EIA report. These are also numbers that aren't collected by survey, but are estimated because refiners don't measure the energy content of either feedstocks or products, which adds further uncertainty to the calculated refinery efficiency. Using the described method, the efficiencies of Paramount's facilities were calculated. The results, along with the regional (by geographic PADD)

refinery and U.S. averages are displayed below in Figure 3. The fuels consumed by average refineries in the same regions are displayed in Figure 4 along with Paramount's fuel. (PP1)

Comment: Using this methodology, Paramount has a calculated efficiency above 96% which is substantially more energy efficient than the average California refinery. Using the average energy intensity factors from the latest 2008 Argonne work on refinery efficiency (http://www.transportation.anl.gov/modeling_simulation/GREET/pdfs/energy_eff_petrolium_refineries-03-08.pdf) combined with Paramount's refinery efficiency, the Paramount product efficiency factors are calculated as 93.7% for CARBOB and 95.1% for CARB diesel. Even after these efficiencies are adjusted downward by a percent to "California-ize" (the GREET v1.8 model product efficiencies were reduced slightly to account for depentanizer power (for CARBOB) and additional hydrogen (for CARB)), Paramount almost has an 8% higher efficiency than the values used to establish the baseline value for LCFS. In other words, Paramount (and other non cracking refineries) use about half the fuel of the average refinery in California to produce a gallon of crude oil based products. Since the refining portion of the lifecycle for CARBOB represents about 14% of the CO₂ emitted, the higher efficiency of Paramount's low energy process means Paramount's products will emit about 7% less CO₂ than the LCFS baseline. The grams CO₂ equivalent/Megajoule (gCO₂e/MJ) for Paramount's CARBOB and CARB are calculated to be less than 90. As a result, we believe Paramount's products are already more than halfway to the 2020 target goals of 86.3 and 85.2 gCO₂e/MJ as shown in Figure 5. below This reduced complexity is, as previously documented, a competitive economic disadvantage to Paramount. CARB should not also punish Paramount by ignoring the lower carbon intensity of the gasoline and diesel fuel it produces which results in part from its inability to raise sufficient capital to purchase and erect a more complex cracking unit. It is rare that Paramount's economic disadvantage can be beneficial, but in the case of the LCFS, Paramount's relative simplicity results in less energy consumed per gallon of product. (PP1)

Comment: In addition, to require Paramount to reduce the carbon content of its fuels from a lower starting point than the major oil companies is to further penalize Paramount by grouping it with inefficient high energy heavy oil cracking processes used by all major oil companies. Paramount simply wants to be treated equitably in this LCFS adoption process and wants CARB to note that as a result of its simplistic refining process, it bears very little resemblance to larger complex California refineries. (PP1)

Response: These comments were inadvertently duplicated from Comment K-128. Please see response to Comment K-128.

K-166. Comment: Clearly petroleum has more than three pathways, yet the ISOR essentially treats petroleum as if it is generic. Again, this creates an opportunity

for the baseline "CA average petroleum" score to act as a safe haven for an increasingly carbon intensive petroleum product. It is also worth noting the following passage in the NFA petroleum report: "The GHG impact of petroleum estimated herein ranges from 90 to 120 gCO₂e/MJ (grams of CO₂ equivalent emissions per megajoule (MJ) of gasoline fuel consumed), depending on the source of the petroleum and to what extent indirect emission impacts are included. The high end reflects unconventional resources and heavy oil, which can contribute to over 10% of current supplies. These emission estimates do not include all of the effects discussed in this report as some effects – most notably *the* broader economic, price-induced effects of the marginal gallon of petroleum – require further analysis. The range of GHG emissions for average petroleum based transportation fuels used in the U.S. are often reported as having an uncertainty band of +1-1 to 2 gCO₂e/MJ. When indirect impacts, marginal resources, and uncertainties discussed in this report are taken into account, the range in emissions is considerably greater." (NFA2)

Comment: There are several problems with the treatment of petroleum under the draft LCFS rule. We are concerned that the treatment of petroleum will result in increased dependence on increasingly carbon intensive petroleum fuels in the near term. For reasons unclear to the NFA, the ISOR creates a worldwide marginal carbon score for biofuels (which is inherently higher than a state average score) but only creates a California-based average for petroleum. This approach creates a clear "apples to oranges" comparison in a regulation designed to create a level playing field. Even more starkly, the proposed LCFS uses different years for different fuels; for example, the carbon score for petroleum is currently based on 2010 while the biofuel carbon score is based on 2015. The outcome in the LCFS is a scenario in which CA average 2010 gasoline is compared to world marginal 2015 ethanol. A marginal gallon of petroleum has a much higher carbon intensity than a state average petroleum. This sets up a market competition that is skewed in favor of the 2010 average fuel, which in this case happens to be petroleum. While the ultimate treatment of advanced biofuels such as cellulosic ethanol is not yet determined, it is equally important here that marginal gallons are compared to marginal gallons, or average gallons to average gallons. The alternative, and current proposal, skews the relative carbon values of the fuels. (NFA2)

Response: The baseline petroleum fuel analysis is based on data from the California Energy Commission for crude oils currently processed by California refineries. The analysis did in fact include the impacts from heavy crude produced and used in California. As to the potential for use of unconventional resources and heavy oil, program reviews have been mandated in 2011 and 2014 at which time a re-assessment of the crudes being used in California could be considered and appropriate refinements made if warranted. This could address the concerns of the commenter above that higher carbon intensity crudes could be imported into California. Although indirect impacts for crude were determined to be small as presented in the ISOR, potential

impacts including the issue of comparison to marginal crude will be evaluated by the expert workgroup being convened at the Board's request.

The baseline for reducing the carbon intensity for 2020 is the 2010 timeline. The biofuel score is not based on a 2015 time frame as is indicated by this commenter. Ethanol from 2015 is not compared to gasoline in 2010. All fuels are compared to baseline gasoline (and diesel) starting from 2010. The carbon intensities for all fuels for which pathway analysis have been published use most current data available. As for a marginal gallon of crude having higher intensity compared to the baseline, the regulation mandates program reviews in 2011 and 2014 at which time a re-assessment of crudes being used in California at that time could be performed. There is no basis to the commenter statement that the current analysis skews the carbon intensity values towards petroleum fuels. In fact, the staff analysis has concluded that fossil fuel producers have to utilize significant quantities of low carbon alternative fuels (mostly non-fossil based) to comply with the 2020 targets established by this regulation. Pathway analyses have been published for many alternative fuels using waste that have low carbon intensities and likely to assist with compliance once produced in significant volumes.

K-167. Comment: Oil-sands-derived transportation fuels are within the range of life cycle intensities of the crudes currently in the basket and currently used in California. (CAPP2)

Response: Please see the response to comments 157 and 155. ARB has not performed an evaluation of crudes from Canadian oil sands since this crude source was not part of the 2006 California baseline crude mix. However, staff may rely on information from independent studies to evaluate such crudes. If a regulated party uses a crude found to have a carbon intensity significantly higher than the baseline value, that higher crude value will have to be used to determine finished fuel carbon intensities for LCFS reporting purposes.

K-168. Comment: The comment letter submitted by the Renewable Fuels Association (Attachment A) contains the following appendices:

Appendix B

Analysis of Current Feeding Practices of Distiller's Grains with Solubles in Livestock and Poultry Feed Relative to Land Use Credits Associated with Determining the Low Carbon Fuel Standard for Ethanol; by Dr. Jerry Shurson, Professor, Department of Animal Science, University of Minnesota, March 25, 2009

Appendix C

Memorandum Re: Comments on the Use of the GTAP Model for the California Air Resources Board; Informa Economics, LLC

Appendix D

Accounting for Differences in the Timing of Emissions in Calculating Carbon Intensity for the California Low Carbon Fuels Standard, Report by NERA (RFA1)

Response: The reports included as appendices B, C, and D to the Renewable Fuels Association letter provided supplemental analysis and detail that further illuminated the points made in the letter itself. As such, they made it possible for staff to prepare more thorough and detailed responses to the primary set of comments contained in the letter. Section M contains responses that were informed the information in Appendix B. The responses in Section L benefitted from the information in Appendix C, while Section L (under sub-section: Time Accounting) contains responses informed by Appendix D.

K-169. Comment: In consideration of the above factors, the Earth Engineering Center of Columbia University applauds CARB's efforts to increase LFG recovery in California, as well as any other state or federal measure that will help reduce the environmental impacts of waste disposal. Opposition to such measures on ideological grounds is counterproductive. (COLUMBIA)

Response: ARB appreciates the supportive comment.

K-170. Comment: Encouraging the development of LFG to low carbon fuels is not in conflict with policies to divert organic waste from landfills. (WM1)

Response: The Board is in agreement with this comment.

K-171. Comment: Given that the production of domestic-based LNG for transportation fuel requires liquefaction (rather than compression) and truck delivery to a fueling destination, it does not appear that this variation in process should significantly increase the carbon impact of LNG when compared to domestically-based CNG on a "well-to-wheel" basis. (CE1)

Response: The CA-GREET model contains a value of 15.79 gCO_{2e}/MJ for the liquefaction of NG for liquefaction is performed in the United States. This amounts to a significant increase in the carbon intensity of LNG when compared to CNG. This value applies to small-scale liquefiers. Staff has, however, provided updated pathway documents for LNG which considers the use of higher efficiency liquefiers. Using such liquefiers, the WTW carbon intensity for LNG from North American natural gas is only slightly higher than the CNG carbon intensity. It is however, incumbent upon regulated parties to demonstrate the performance of their liquefiers if they are to use this lower carbon intensity pathway.

K-172. Comment: Efficiency of water use – Reward the use of non-irrigated land and water reduction below prior use. We recognize that this may create a need to equate water usage and GHG production. Fortunately, in California, there are models for the embedded GHG effects of water utilization, and we assume that these or comparable models can be applied in the rest of the country where irrigation is used.

Low carbon agricultural practices– Recognize practices that improve the carbon sequestration in soil, including non-till practices and biomass systems, and include appropriate credits in the lifecycle analysis. (EE1)

Comment: A continued shift to more no-till corn production could reduce the amount of CO₂ released in corn production because no-till corn is considered by some researchers as a carbon sink (more carbon is taken up by the soil than is released to the air in corn production). Some research indicates that minimum tillage programs can also reduce the amount of CO₂ released. (ILCORN)

Response: CA-GREET accounts for agricultural water usage based on the industry average water consumption rate for each region. The same is true of tillage practices: the model calculates GHG impacts based on average farming practices in the production region. Specific practices such as no-till are not accounted for. When practices such as no-till become the dominant practice in the production region and can be substantiated by data from the USDA (or other comparable entity), appropriate refinements could be considered to the existing analysis. This can be considered during the 2011 and 2014 mandatory reviews.

K-173. Comment: We believe that standards need to be based on sound, peer-reviewed and updated, scientifically based data and we don't believe that the proposed regulations achieve this because of these factors:

-A recently released peer reviewed publication in the *Journal of Industrial Ecology* titled Improvements in Life Cycle Energy Efficiency and Greenhouse Gas Emissions of Corn- Ethanol has shown that corn based ethanol reduces direct greenhouse gas (GHG) emissions by 48% - 59% as compared to gasoline. California LCFS tables do not reflect this peer reviewed information.

-The adoption and usage of data of current production practices, input efficiencies and yield are missing. According to various National Agriculture Statistics Service and Economic Research Service reports, yield is increasing at a much faster pace than previously predicted. Growers have also increased fertilizer efficiency greatly over the past thirty years. Unfortunately, the CA-GREET model does not incorporate all of these yield advances and improved efficiencies.

-Updated feeding rates of co-products and their adjusted credits. Dr Michael Wang, et al in September, 2008 released up to date feeding and displacement ratios for distiller's grains. The update shows that for each pound of distillers grains that is placed in a ration, it replaces 1.28 pounds of conventional corn and soy-based feed. This displacement is greater than the current ration CARB is using and the new data should be incorporated into the model. (MCGA)

Response: The Board's direct lifecycle analysis of corn ethanol yielded results similar

to those reported in the article referenced in this comment. The full fuel pathway carbon intensity for corn ethanol, however, contains a land use change component (see the responses to the comments in Section L (“Land Use Change”). It should also be noted that there are publications that indicate much higher carbon intensity values for corn-derived ethanol than those listed in the LCFS look-up table. The Board relied, however, on the well documented, peer-reviewed GREET model to provide more representative values. The CA-GREET model uses current yields and efficiencies, but the LCFS regulation allows for potential improvements to be accounted for, as they are verified. As for issues related to the replacement credit for distiller’s grains, see the response to Comment M-1.

K-174. Comment: Definitions and terminologies need to be consistent. For example, the terms “Total Energy Use” and “Total Energy” have been repeatedly used in several documents without differentiation. It was not clear whether these two terms were equivalent. Additional clarification and consistency are necessary (CONOCO)

Response: The pathway documents are created to elucidate the various inputs, calculations, assumptions, etc. inherent in the CA-GREET model. Though adequate care has been taken to ensure consistency, different, but similar terms may occasionally be used interchangeably. The terms “Total Energy Use” and “Total Energy,” for example, are used synonymously in the pathway documents. Because these terms are nearly identical in both construction and meaning, revising all affected documents to achieve consistent use was deemed unnecessary.

K-175. Comment: Sempra Energy still has concerns about the accuracy of the pathway and GREET Model data inputs that are used to derive carbon intensities related to natural gas fuels. We appreciate the efforts staff has made to further evaluate these inputs and recognize that this analysis is ongoing. For this reason, we suggest that no values for natural gas fuels be included in the Look-Up Table at this time and that the Executive Officer use the authority provided in section 95486 to add these values during the next several months. Alternatively, we suggest that a paragraph be added to the Board Resolution of adoption stating that the values for natural gas fuels in the Lookup Table are still being reviewed. (SEMPRA1)

Response: The ISOR analysis was prepared using CA-GREET, a California-specific version of the peer reviewed, publicly available GREET life cycle analysis model. The inputs and assumptions used for the natural gas analysis are robust and reflect an accurate analysis of this pathway. Staff has subjected the natural gas pathway to additional scrutiny, and released the results for further public comment. Because this process has resolved all remaining significant uncertainty in this LCFS pathway, no further revisions are planned at this time. The Board has mandated program reviews in 2011 and 2014, however. Additional refinements could be considered during one or both reviews.

K-176. Comment: We support the complete lifecycle and pathways analysis, so as to promote production and consumption of biofuels from local sources whenever possible. While California has a low potential for native oilseed crops, it offers a substantial resource in the form of waste oil. The local nature of this resource offers maximum carbon reduction due to its inherently efficient pathways and zero land-use. Lifecycle analysis also will help to encourage support of algae based feed stock, which we expect to comprise a larger portion of the feed stock pool in the coming decades. California is an ideal climate for algae production as evidenced by NREL's study which was based in California back in the nineties. (SFB2)

Response: This comment is generally consistent with the objectives of the LCFS, primarily the objective of incentivizing the development and marketing of low-carbon fuels. The Board anticipates that alternative fuels that do not induce land use change will be among the lowest-carbon fuels available in the California market. Diesel produced from waste cooking oil is an example. A fuel pathway and a fuel lookup table entry currently exist for this fuel. As such, suppliers of waste-cooking-oil-based biodiesel will be able to begin earning credits as soon as the regulation goes into effect. The Board also anticipates that algal biodiesel holds much promise as a low-carbon fuel. Because production processes for this fuel are still under development, no pathway has yet been developed for algae-based fuels. Producers who are ready to bring new fuels to market, however, may apply to the Board for the creation of the necessary new pathways under the Method 2A and 2B provisions of the LCFS regulation. Upon Executive Officer or Board approval, Method 2A and 2B pathways are available to qualified producers, who can then begin earning credits as their fuels are sold on the California market.

K-177. Comment: I also write to urge ARB to develop and publish LCFS fuel pathways for biodiesel produced in California and for biodiesel using waste feedstocks such as used cooking oil and inedible animal fats. (GDSF)

Response: Approved pathways and lookup table entries for biodiesel from used cooking oil and tallow (inedible animal fat) currently exist. Providers of these fuels can begin to earn credits when the LCFS goes into effect.

K-178. Comment: The carbon intensity penalty assessed on the ethanol industry improperly discriminates against and burdens interstate commerce; and the environmental impacts from the regulation are inadequately evaluated. (GE3)

Response: For interstate commerce issues see the response to Comment E-41, and for environmental impact evaluation see the responses to comments in Section F (Environmental Impacts).

K-179. Comment: When judging fuels for carbon intensity all fuels must take into account all cradle to grave carbon adding activities that includes pumping salt water into oil wells and transportation to refinery. Please do not include Bio-

Diesel in with Ethanol. The only way ethanol will work in California is with a lot of transportation from mid-west states, that is carbon intensive. Bio-Diesel is made in Las Vegas with very little transportation footprint. I believe this board is dead set against California getting Energy independent. Please do not destroy the chance of locally produced Bio-Diesel from competing against regular Diesel. (BELLIZI)

Response: The CA-GREET model used in the fuels pathway reports accounts for the total energy used and attendant GHG emissions in the recovery and transportation of crude to a refinery (cradle to grave or Well-to-Wheel).

Within the LCFS framework, ethanol and biodiesel are not in competition. Ethanol is a potential alternative to gasoline while biodiesel is an alternative to ULSD.

For biodiesel, staff has published pathways using used cooking oil and will soon publish a pathway for biodiesel using soy oil. The used cooking oil pathways are modeled as being sourced in California and have a low carbon intensity relative to petroleum derived diesel. As for biodiesel sourced from other regions such as Las Vegas, there exist Methods 2A and 2B to allow producers to model their fuel pathways for inclusion as a LCFS fuel in California. The regulation clearly indicates that the objective is to reduce dependence on current fossil-derived fuels by promoting and incentivizing the development of alternative low carbon fuels.

K-180. Comment: I am writing to you on behalf of Illinois River Energy, LLC; a fuel ethanol producer located in northern Illinois. As a company founded on the principle of the importance of renewable energy to the future of our society, we applaud the commitment that California has made in reducing its environmental impact. We are concerned, however, with the inaccuracies regarding the comparison between gasoline and corn based fuel ethanol in the data being utilized to make recommendations to the California Air Resources Board (CARB) via the proposed Low Carbon Fuel Standard (LCFS). We believe these inaccuracies, resulting in the reduction of corn based ethanol will have a negative impact on global warming.

We are confident in the inaccuracies in the report because of the work we at IRELLC have done to ensure the environmental stewardship of our own production facility and its fuel ethanol product. IRELLC is a modern day dry grind natural gas fired fuel ethanol production facility. These studies (Dr. S Mueller of the University of Illinois at Chicago) determined: corn based ethanol from IRELLC, including all of the parameters established in GREET as well as indirect land use, has a GWI of 54.8 gCO₂e/MJ relative to a GWI for gasoline of 92.1 gCO₂e/MJ. (IRELLC)

Comment: It is disturbing, at best, to have default values for dry grind corn ethanol in the LCFS model that fail to recognize a true and accurate accounting of the GWI of an individual ethanol production facility. Clearly, fuel ethanol, from

a plant such as IRE could provide California petroleum blenders with a fuel with a demonstrated dramatically improved carbon footprint relative to gasoline today. Additionally, this fuel would provide California consumers with an economic domestic means of improving our environment. (IRELLC)

Comment: According to Table ES-8 from CARB's recommendation (attached), CARB has determined carbon emissions for the production of corn-based ethanol from the most common Midwest natural-gas-fired dry mill to be 98.40 grams CO₂/MJ (including CARB ILUC adder of 30). In comparison, CARB has determined gasoline based on the average crude oil delivered to California to be 95.86 grams CO₂/MJ. In this example, Midwest ethanol has higher carbon intensity than gasoline. Such an illogical misrepresentation of Midwest corn ethanol carbon intensity, based on an ILUC adder of 30, would therefore serve to prohibit the blending of typical Corn Belt ethanol with gasoline in California. Regardless of any free-market discussions by CARB staff, the LCFS regulation, as it is intended, will serve as a trade barrier for corn ethanol produced outside of California. Such an approach will not reward the producer of low carbon ethanol; rather it will label ethanol as good or bad for use in California. Ethanol must be rated and marketed by field-to-wheels-carbon intensity as calculated at each production facility. The free market will place a premium on low-carbon ethanol produced or delivered to the California marketplace, and it will reward the producer, distributor, and blender accordingly. (ICM1)

Response: The Carbon intensity value in the Lookup Table is the average value for NG fired dry mill based corn ethanol. Producers whose processes yield significantly lower carbon fuels are free to apply to the Board for a new pathway that better reflects those processes. The Method 2A and 2B provisions of the LCFS regulation allow such producers to pursue more suitable fuel pathways.

For responses to comments concerning the Board's inclusion of land use change increments in the carbon intensities of corn ethanol, please see Section L ("Land Use Change").

K-181. Comment: Ohio applauds your leadership in promoting alternative fuels. Increasing America's energy resources and protecting national security by reducing our dependence on foreign oil, in addition to, continuing to grow our domestic renewable fuels industry are among the most important challenges facing our country. As corn growers we play an important role in reducing our dependence on foreign oil. However, we are deeply concerned, about the trajectory of the current LCFS proposal in your state. (OCGA)

Comment: It is vitally important to note that corn production is becoming increasingly more efficient. Today, through technological advances America's corn growers have the ability to apply fewer inputs to produce larger crops on the same land. Currently it takes about 40 percent less land to grow a bushel of corn than in 1987, and energy used to produce a bushel of corn has fallen by an

average of 50 percent. According to Keystone Center's "Field to Market" report released in January 2009, the production of corn in the U.S. has made significant measurable improvements in reducing energy, water, land use and carbon emissions. U.S. farming practices are advancing and will continue to advance in terms of sustainability and productivity. For example, according to the United States Department of Agriculture (USDA), in 2008 American corn growers produced the second largest corn crop on record and attained the second highest yield per acre in history with fewer energy and fertilizer inputs. In addition, the dried distillers grains that are a co-product of ethanol production are playing a major role in providing livestock—in the U.S. and abroad—with high-protein, nutrient rich feed. (OCGA)

Comment: In addition, a multitude of other studies and reports have recently been released that further underscore the inherent problems with the theory of indirect land use change. One article, published in the Journal of Industrial Ecology, shows that modern corn biofuel production facilities emit an average of 51 percent fewer greenhouse gas emissions than gasoline, thanks to technological innovation.
(ACE)

Comment: I cannot support the carbon intensity penalty imposed on ethanol fuel. This penalty is highly controversial and not well supported from a number of perspectives, for example, good science, good public policy, fair treatment, national security. Such a penalty rests upon a very questionable theory and a very questionable immature methodology for identifying and quantifying the indirect land-use effect changes from the production and use of ethanol fuel. Not all fuels, not all indirect effects of all fuels, but one fuel, one indirect effect, and one industry singled out. If this fuel standard is added to, adopted with this penalty included, here is what likely to happen to the ethanol industry in this country. (JMBM)

Response: The issue of corn yields is discussed in detail in the section entitled "Crop Yields, Production Yields, Agricultural Intensification" in Section L ("Land Use Change") of this FSOR. The general rationale for the Board's inclusion of a land use change increment in the carbon intensity of corn ethanol is described in the responses to the comments in the section entitled, "Unavailability of Land Use Change Estimation Methods" found in Section L. For responses to the comment that the inclusion of a land use change increment in the carbon intensities of crop-based biofuels unfairly penalizes those fuels, please see the Section entitled, "Indirect Effects Only Assessed Against Biofuels" in Section L. The co-product credit earned by DGS in the LCFS corn ethanol lifecycle analysis is discussed in the response to Comment M-1).

The LCFS is designed to reward fuel innovative fuel producers who improve the efficiency of any fuel pathway. Such producers are encouraged to apply the Board for the establishment of a new sub-pathway. A new corn ethanol sub-pathway would make the lower carbon intensity of a more efficient production process available to qualified

producers. The Method 2A provisions of the LCFS regulation provide for the establishment of new sub-pathways in response to applications initiated by producers.

K-182. Comment: If Paramount's calculated carbon intensity values were correctly identified because of its process efficiency, Paramount would not be in a credit deficit condition until 2018 as seen in Figure 5. (PP1)

Response: ARB staff recognizes that differences likely exist between large and small refineries in terms of energy use and GHG emissions. However, to avoid shuffling (where heavy crude from California is shipped out of state for refining and lighter crude is imported into California for refining within state), the ISOR chose not to assign refinery specific GHG emissions and a separate standard for different size of refineries. The Climate Action Bill, AB32 will regulate each refinery based on its individual GHG emissions. Additionally, the Board has mandated program reviews in 2011 and 2014 at which time, this issue could be re-considered. See also the response to Comment K-127.

K-183. Comment: PFT also supports the inclusion and exploration of fuel pathways derived from forest biomass. While the ability of forest resources to contribute to a new generation of biofuels may be limited—currently due to technological constraints and ultimately because of a limited supply of appropriate feedstock material—with robust ecological sidebars in place, forest-derived cellulosic ethanol can play a supportive role in the LCFS. (PFT)

Response: The Board is evaluating the establishment of a pathway for fuels using forest biomass as a feedstock. If it can be shown that such a pathway can operate sustainably, it will be considered for adoption.

K-184. Comment: We do have concerns with a number of the issues relating to the pathway analyses. We've submitted these in writing. They relate to the treatment of perennial grasses yields, ag practices and productivity, technology timelines. (DUPONT2)

Response: See responses to Comments K-105, K-106, K-107, and K-119.

K-185. Comment: There are many reasons these predictions could be wrong and the greenhouse gas emissions from a biofuel yet much larger. One study by the European Union's Joint Research Center estimated that if only a 2.5 percent of the vegetable oil diverted to biodiesel were replaced by palm oil plantations established in peatlands, the emissions from the peatlands alone would eliminate any greenhouse gas benefit from replacing diesel fuel. (PRINCETON)

Response: The biofuel carbon intensities appearing in the LCFS lookup table were estimated using the most current and most relevant data as well as the best available predictive models. The initial estimates obtained from the application of these models and data subsequently benefitted from months of thorough public review, and were

appropriately revised to reflect the technically sound comments received during the review period. The Board has determined that the resulting values are sufficiently robust to support the implementation of an effective Low Carbon Fuel Standard. The Board also acknowledged, however, that the remaining uncertainty associated with LCFS biofuel carbon intensity values must be reduced. Although some of the information submitted during the comment period indicates that the Board's estimates are too high, a number of studies and comments (this one included) suggest that the Board's estimates are too low. In order to help reduce this uncertainty, the Board directed staff to convene an expert workgroup to refine and improve the land use change analyses supporting the LCFS, and to provide recommendations to the Board by January 1, 2011. The Board has also mandated two program reviews to be completed in 2011 and 2014.

K-186. Comment: We understand that the pathway for ethanol from forest waste is still under development and not ready for adoption at this time. From our perspective this is quite positive, as it should give ARB staff the opportunity to reconsider factors included in the lifecycle analysis. As it stands, the lifecycle analysis starts at the point of wood waste collection; however, this is not the starting point of production. To create wood waste, trees are grown and a forest is harvested at varying degrees of intensity. The full GHG profile of forest waste thus needs to include the energy input for the entirety of the forest management operation, including monitoring for significant carbon stock depletion over time. If harvest levels are intensified to take advantage of new bioenergy markets, then the waste's GHG value will also increase.

With the current lifecycle analysis, there is no mechanism to capture this potential effect. We would encourage further refinement of the lifecycle analysis to include the production stage of forest growth and harvest operations. This completes the true full lifecycle, and would help to avoid shifts in forest management that result in significant carbon stock depletion or degradation of other critical ecological values (PFT)

Response: Although it is not clear that emissions associated with forest growth and harvesting would need to be accounted for in the carbon intensities of forest waste feedstocks (timber harvesting is not the only source of wastes), the Board agrees that forest wastes must only be used to produce LCFS fuels if they can be sustainably harvested. As this comment suggests, one approach to enforcing sustainability is to assure that the carbon intensity of forest-waste-based fuels truly reflects the ecological health of the forests from which the feedstocks were harvested. Overharvested wastes would earn higher carbon intensities relative to sustainably harvested wastes. Another approach would be to rely on a sustainability certification program to identify wastes that are acceptable as feedstocks for LCFS fuels. The Board is currently assessing the relative efficacy of these and other approaches, and will not approve a pathway for forest-waste-based fuels unless and until verifiably sustainable harvesting techniques are in place.

K-187. Comment: Cellulosic ethanol and other second-generation crops have problems in need of consideration as well. For example, "Even the planting and harvesting of 'sustainable' energy crops can have a negative impact if these replace primary forests, resulting in large releases of carbon from the soil and forest biomass that negate any benefits of biofuels for decades." Meanwhile, the total water requirements for ethanol from cellulose are thought to be large-about 9.5 gal/gal, but this likely will decline as efficiency increases. There are two additional steps required in converting lignin and cellulose into starch, and these operations could produce wastewater streams that are high BOD and would require on-site treatment or treatment at publicly-owned treatment works. Although cellulosic crops hold soil better than corn in general, they can also pose problems of nutrient leaching and erosion, raising substantial concerns. Finally, while several studies have suggested that cellulosic ethanol will provide a significant carbon benefit over corn ethanol, research has been ongoing for greater than 15 years to produce cellulosic ethanol, yet such technology has not been developed to date at the industrial scale. Thus, "all calculations of carbon cycling during production and consumption of cellulosic ethanol are hypothetical and premature." (CERA2)

Response: The Board is committed to performing the most comprehensive life cycle analyses possible on all LCFS-regulated fuels. As such, each of the potential sources of GHG emissions alluded to in this comment will be considered in the analyses performed on cellulosic fuels. The water usage, treatment, and pollution issues raised in this comment will be considered in the sustainability criteria staff is developing in response to directives contained in Board Resolution 09-31. The commenter is correct in pointing out that cellulosic fuels have yet to be produced on a commercial scale. The market incentives designed in to the LCFS should, however, hasten the development of cellulosic fuels that are likely to receive low carbon intensity ratings.

K-188. Comment: For petroleum fuel pathways, an inconsistency was observed in the allocation of energy and emissions for crude recovery and transport between CARBOB and diesel. The same energy input, 80,345 BTU/MMBTU was used for crude recovery for CARBOB and ULSD pathways. Based on LCA principles, total energy use and emissions for crude recovery and transport should be allocated between co-products derived from the crude oils (predominately CARBOB and ULSD). The allocations can be made by mass fraction, energy content, market value or substitution. Based upon public information, U.S. refineries produce more gasoline than diesel (volume ratios approximately 2 to 1). Therefore the number for crude recovery should not be the same for CARBOB and ULSD. (CONOCO)

Response: The allocation method used for CARBOB and ULSD is the same approach as applied in the CA-GREET model. CA-GREET bases the fuel cycle energy (WTT) on the production of 1 mmBtu of fuel and 1 mmBtu of feedstock to produce that fuel. Therefore, the energy assigned for the 1 mmBtu will remain constant. The allocation for the energy inputs for crude oil production are effectively taken into account in the WTT

phase associated with crude oil refining. The energy inputs and emissions associated with crude oil production are reflected in the crude oil portion of the refinery category in CA-GREET. According to the allocation method used in the CA-GREET model, crude recovery and transport energy expenditures and GHG emissions are allocated to finished fuels on a per-unit-energy basis; on this basis, the allocations to gasoline and diesel fuels are equal.

K-189. Comment: We think we need to complete the unfinished work related to diesel fuels before adopting a carbon intensity standard for diesel. (CMTA)

Comment: To position LCFS for success and minimize the cost and job losses and any unintended environmental consequences, we ask that you postpone adoption of the rule until we have a complete analysis. We need three things -- we need at least three things: Complete -- the incomplete life cycle analyses, notably those for biodiesel or renewable products -- renewable diesel products; Demonstrate the availability and cost effectiveness of sufficient lower carbon fuels to meet the standard through 2020 using existing technologies based on publicly available information; and identify the degree to which the standard will require development and commercialization of materials and technologies that are not yet commercially available. (CMTA)

Response: Staff has published pathways for fuels that when blended with diesel could provide GHG emission reductions to allow for compliance with the LCFS. Staff also recognized that commercial production of adequate quantities of diesel replacements are likely to happen beyond 2012 and appropriately set smaller compliance targets for the initial years of the regulation through 2014. Pathway documents for soyoil based biodiesel and renewable diesel are being updated and will be published soon for public comments. Additional pathways are being planned for early 2010 and producers are being encouraged to work with staff on developing their product pathway carbon intensity based on Methods 2A and 2B. With all this effort, staff feels that adequate work has been completed on diesel replacements and additional efforts are on-going.

Staff has presented an economic analysis of the cost of low carbon fuels and based on this analysis, such fuels will be available and at reasonable prices relative to fossil fuels. An environmental analysis also concluded that harmful impacts from toxics and criteria pollutants from the adoption of the LCFS is unlikely in California. A siting document to assist biorefinery plants likely to be built in California is being prepared and this takes into account mitigating of environmental impacts from criteria pollutants and toxics.

Finally, to incentivize the production and availability of low carbon fuels, staff has generated several pathway documents that detail feedstock-fuel pairs likely to produce low carbon fuel for use in the California market. The regulation also included in it, Methods 2A and 2B to enable producers of current fuels to improve their processes to lower the carbon intensity for their fuel or establish new pathways for novel feedstock-fuel pairs likely to be commercialized in the future.

K-190. Comment: As an example, corn ethanol biorefineries operating in California are the most efficient, least greenhouse gas emitting plants in the country while at the same time they produce a high value feed product for our dairy and beef industries. (AGBC)

Response: The Board's analysis confirms that California corn ethanol refineries are generally the most efficient in the U.S. The information contained in LCFS pathway documents and carbon intensity lookup table document this finding. The values appearing in these sources reflect the full lifecycle carbon intensity of corn ethanol, including the carbon credit earned for the production of distillers' grains (DGS)—a co-product used for livestock feed. For more information on the corn ethanol co-product credit, please see Section M of this FSOR, and Appendix C11 of the ISOR.

K-191. Comment: In addition, before the feasibility of the standards can be fully evaluated, there are a number of issues that must be resolved. First, the underlying lifecycle emission models, methodological choices and input data sets and accompanying assumptions used to determine the CI of fuels have yet to be settled and fixed so that accurate and consistent assessments of the CI can be established for all fuels. (SHELL)

Response: The Board has settled on the use of the CA-GREET model to assess direct lifecycle GHG emissions, and the GTAP to estimate emissions from land use change impacts. Both models, and the data supporting them are well-documented and peer-reviewed. Their use in the development of fuel pathways under the LCFS has been subjected to an extensive public review process which has generated a large number of comments. Revisions have been made, as warranted, to reflect the technically sound comments received. The results will undergo continued evaluation in period program reviews, and in an expert workgroup which will advise the Board on ways to improve and refine the land use change analysis. The program reviews and the expert workgroup are mandated in Board Resolution 09-31.

K-192. Comments: We support the complete lifecycle and pathways analysis so as to promote production and consumption of biofuels from local sources whenever possible. While California has a low potential for native oilseed crops, it offers a substantial resource in the form of waste oil. The local nature of this resource offers maximum carbon reduction due to its inherently efficient energy pathway and zero land use. Need to complete addition pathways for diesel and renewable diesel. (CMTM)

Comment: Any shift in California's fuel supplies must be carefully vetted to ensure it does not cause operation problems or have supply or price impacts. Specifically, we believe the following is needed to better understand the proposed rule: determine the critically important carbon intensities for biodiesel, renewable diesel, and advanced renewable diesel; (CCOC)

Response: The Board directed the ARB staff to publish pathways for biodiesel and renewable diesel and the results have been incorporated in the Lookup Table. We will develop additional pathways once data becomes available. The priority for the development of new pathways will be based on which fuels are closest to coming into use in California. Fuel producers can also use Methods 2A and 2B to establish additional pathways.

K-193. Comment: As a general approach, we have recommended and continue to recommend that each fuel, crude, ethanol based, electric vehicle... be subject to its own individual pathway assessment. However, in practice, there may be benefits for administrative simplicity of having all crude oils assigned one value. Regardless, any LCFS policy must be based on sound science, and be open and transparent. (AE1)

Response: ARB has established fuel pathways which cover the majority of fuel production scenarios. For crude oil, except for high carbon intensity crudes not used in California in 2006, ARB has assigned one value taking into account the 2006 California crude mix as reported by the California Energy Commission. The analysis presented in the ISOR and approved by the Board was based on the best available data on the practices used to produce feedstocks and finished fuel, as described in the fuel pathway documents available on the LCFS web site. The information used and the methods applied were presented at several workshops. Staff solicited and received a large volume of comments from participating stakeholders. Where appropriate, staff revised the published pathway information to reflect the technically sound comments received. The indirect Land Use Change analysis utilized a peer-reviewed, publicly available model. As a result, the fuel pathways and carbon intensity values the Board has released are scientifically defensible, and sufficiently robust to serve as the basis for the LCFS. In order to address some of the remaining uncertainty in those carbon intensity values, the Board directed staff to convene an Expert Workgroup to help refine and improve current land use change estimates. Recommendations from this group are required by December 2010. Additionally, there are two mandated reviews in 2011 and 2014 when additional refinements could be considered.

K-194. Comment: Crude derived transportation fuels are and will remain the mainstay in California for decades. Based on CARB's projections, crude oil demand in 2020 will be around 80 percent of today's level. We suggest that what CARB is proposing is a stretch policy, one that is not actually achievable in the time frame proposed. Therefore, the role of crude going forward will not be diminished as envisioned by this LCFS "off-oil" policy; rather its transitional role may be enhanced. This is a concern because the regulation provides no recognition, let alone incentive, for process improvements in the upstream crude industry. What the regulation does is expressed in the following excerpt from your report: "... the proposed LCFS regulation will result in a shift of capital from the petroleum sector to the agricultural, chemical, and electricity and natural gas sectors" (AE1)

Response: ARB analyses demonstrate the feasibility of achieving the LCFS goals within the timeframe allowed. The LCFS is designed to reduce the demand for fossil fuel in California and to incentivize the production and use of lower carbon intensity alternative fuels. Improvements in the upstream crude industry will be accounted for in the AB32 refinery sector requirements.

K-195. Comment: Well-to-wheel GHG emissions can also vary substantially on the basis of different cultivation practices and fuels used to process biofuel. It is not possible to classify biofuel as “good” or “bad” on the basis of the feedstock they are developed from alone. (VALENTE)

Response: The LCFS does not classify biofuel as good or bad. It assigns appropriate CI values to each fuel that reflects production, processing and transportation and fuel use practices. CA-GREET for biofuels uses farming data published by USDA and other government agencies. It would be impractical to evaluate farming efficiencies on a farm by farm basis. However, when new farm practices are employed industry-wide they can be incorporated into the analysis. The analyses published for the values in the LCFS Lookup Table accurately represent an average of different cultivation practices and fuels used to process the biofuel pathways.

K-196. Comment: This comment consists of a summary of the Report entitled “Motor Vehicle Fuels: Concepts for a Rational and Sustainable National Energy Policy” by Econergy International Corp. 2/9/2009. This is a policy paper promoting low-carbon fuels.

- From the Executive Summary:
Market-based incentives must be created to incentivize the large fleet of existing corn ethanol production facilities to increase their efficiency. Specific actions toward this end include creating a production tax credit aimed specifically at industrial process heat (IPH) to encourage existing ethanol plants to switch from fossil fuels to carbon-neutral thermal energy sources for their IPH needs.
- Establish a motor fuel carbon-content standard (grams CO₂e/MJ) so that the marketplace will reward ethanol producers, distributors, and blenders for supplying lower-carbon vehicle fuels. Encourage the use of low-cost and low-carbon Brazilian sugarcane ethanol within a market-based framework that drives down the carbon intensity of motor fuels.
- Establish national fuel rating system. Recommends a 2-phase CO₂ emission reduction strategy similar to the LCFS’: a 2.3% CO₂ reduction by 2015 and a 4.9% CO₂ reduction by 2022
- Incrementing fuel carbon intensities to reflect land use change impacts is not justified due to the immaturity of available scientific evaluation methods.

- Establish well-to-wheels emissions targets. EU vehicle manufacturers, for example, are required to meet 140 gCO₂e/km which will be lowered to 120 gCO₂e/km by 2012
- Transition to sustainable ethanol (using non-food feedstocks) by starting immediately with low-carbon varieties of corn ethanol
- Promote electric and plug-in hybrid EVs.
- Coal-to-liquids fuels and fuels from tar sands and shale oil should not be part of the strategy because they increase GHG emissions.
- Consider the Net Renewable Energy Value (MJ/L) and Net Renewable Energy Ratio: Brazilian sugarcane ethanol returns 62% more renewable energy than ethanol from the modern dry-grind, natural-gas-fired plants operating in Iowa
- Expresses support for the New Fuels Alliance letter of 10/23/2008, included as Appendix C
- Describes Ecoenergy's carbon mode ("ICM/Ecoenergy Model")—a life cycle analysis model. Presents an application of that model to an individual ethanol plant.
- Recommends evaluating corn ethanol carbon intensity on state-of-the-art production plants: Midwest dry-grind plants with combined heat and power, fueled by corn stover. Such plants have a CI of 20.9 gCO₂e/MJ, which is lower than 26.1gCO₂e/MJ for Brazilian sugar cane ethanol
- Econergy recommends that the 2015 target carbon intensity for average gasoline-ethanol blends be set at 89.5 gCO₂e/MJ (ICM3)

Response:

- The LCFS creates incentives for fuel providers to provide low carbon intensity fuels, regardless of their origin. Tax incentives are outside the scope of the LCFS. The LCFS establishes a fuel carbon standard which rewards producers, distributors, and blenders for supplying lower-carbon vehicle fuel including low carbon ethanol.
- National standards such as a national motor fuel carbon content standard and a national fuel rating system are outside the scope of the LCFS.
- For a detailed discussion of the rationale behind the inclusion of land use change impacts in affected fuel carbon intensity values, as well as the rationale behind the Board's choice of a land use change estimation model, please see the responses to the comments in Section L, "Land Use Change."

- WTW emissions targeting EU vehicle manufacturers are not relevant to this rulemaking. The LCFS provides for performance standards and does not discriminate against different varieties of ethanol.
- The LCFS is designed to incentivize the development of lower-carbon ethanol, as well as the use of electricity as a vehicle fuel. The LCFS has established different pathways for ethanol based on the feedstocks used and the different processing methods. The analysis presented in the ISOR uses the most current data available for the fuel pathways. To account for pathways for ethanol which may have actual carbon intensities lower than the values listed in the Lookup Tables, the LCFS includes a mechanism by which producers of such fuel may apply to the Board for new fuel pathways that better reflect their specific processing methods (Methods 2A and 2B). Staff is currently working on a sustainability policy to assure that unsustainably produced fuels will not be unduly rewarded under the LCFS, even if their carbon intensities are below those of the applicable reference fuels.
- Fuels based on high carbon-intensity crude oil are discussed in the responses to the comments appearing in Section C, “High Carbon Intensity Crude Oils.” It appears at this time that transportation fuels produced from coal would not have a carbon intensity significantly below that of the LCFS reference fuels (reformulated gasoline and CARB diesel), and would not, therefore, be able to play a significant role in the California fuel market.
- Neither the Net Renewable Energy Value (MJ/L) or the Net Renewable Energy Ratio metrics has been employed in the development of the LCFS. The commenter may wish to bring these metrics to the attention of the Board at one or both of the program reviews which the Board has mandated for 2011 and 2014
- The points raised in the New Fuels Alliance letter cited in this comment are responded in the appropriate sections of this FSOR.
- The Board currently uses the CA-GREET model to evaluate both average and specific fuel pathways. If the commenter wishes to propose an alternative model, that could be accomplished at one or both of the program reviews the Board has mandated for 2011 and 2014. Moreover, the primary fuel pathways appearing in the LCFS lookup table necessarily represent industry average production methods. Producers wishing to add pathways that better reflect their specific production processes may apply to the Board for the creation of new fuel pathways under the Method 2A and 2B provisions of the LCFS regulation.
- As a performance-based regulation, the LCFS does not establish targets for specific fuels. Instead, it sets annual carbon intensity ceilings that fuel providers must meet, but does not dictate how compliance strategies. Providers may comply by supplying any combination of approved low-carbon fuels, or by using purchased or banked credits.

K-197. Comment: The relatively large uncertainty inserted in the baseline target carbon intensity as a result of the estimates (instead of true measurement) used by Argonne to determine average refinery efficiency as well as the "Rule of Thumb" basis used for the product energy allocation dwarfs the very small change (approximately .1 gCO₂e/MJ) in the 2020 goal that would be required to exempt the non-cracking refiners from this regulation. The uncertainties in other portions of the LCFS such as indirect land use and ethanol by-product allocation create much greater uncertainties in the results of LCFS than this very tiny change. Effort should be directed to the improved accuracy of the many unknowns in the LCFS determinations to increase the confidence of achieving the goal rather than to penalize already efficient fuel suppliers (PP1)

Comment: Reduced complexity is, as previously documented, a competitive economic disadvantage to Paramount. CARB should not also punish Paramount by ignoring the lower carbon intensity of the gasoline and diesel fuel it produces which results in part from its inability to raise sufficient capital to purchase and erect a more complex cracking unit. It is rare that Paramount's economic disadvantage can be beneficial, but in the case of the LCFS, Paramount's relative simplicity results in less energy consumed per gallon of product. (PP1)

Response: The LCFS regulation does not penalize efficient fuel suppliers by including average refinery efficiency. The Board decided to use an average refinery efficiency in the LCFS because differences in refinery efficiencies will be accounted for in AB 32 refinery improvement strategies where each refinery will be evaluated separately. We also believe that the approach of using separate values for different refineries and of having different targets for different refineries would create a regulatory structure that would be impossible to monitor and enforce. The Board-mandated regulatory reviews in 2011 and 2014 could investigate such concerns further. Although the Board has determined that the uncertainty surrounding the carbon intensity values appearing in the LCFS lookup table have been steadily reduced during the LCFS comment period and are now well within an acceptable range. Much of the remaining uncertainty in the lookup table values is attributable to the land use change component contained the carbon intensities of certain crop-based biofuels. For detailed discussions of this component, please see the responses to the comments in Section L ("Land Use Change") of this FSOR. Ethanol co-product allocation issues are discussed in the responses to Comments K-181 and M-1.

K-198. Comment: The backloaded compliance schedule, the inclusion of the enforcement protocols, and the evidence of the physical pathway, are things we do support in the regulation. (WSPA3)

Response: The Board agrees that the regulatory components listed in this comment are key to the success of the LCFS.

K-199. Comment: As part of the crucial next phase of implementation, it will be very important for CARB to continue to refine and update its input data, assumptions

and methodologies underlying its LCFS pathway analysis. (SCAQMD)

Response: Staff has published several fuel pathways in 2008 and 2009. ARB continues the work to develop additional pathways for feedstock and fuels that are expected to participate in the California market. In addition, refinement of the existing pathways and data collection will continue. The Board has directed staff to establish an Expert Workgroup that will look at assumptions, inputs, and models used in the pathway analysis. There are also two mandatory program reviews in 2011 and 2014 that will revisit the analysis.

K-200. Comment: At the March 27, 2009 LCFS workshop ARB staff expressed that customers will decide the winners on the market by picking vehicles and fuel. We see this as a massive waste of investments in a patchwork of different (and crazier) fuel types and differing infrastructure requirements. Customers may not know the drive train efficiencies or carbon intensity requirements to maximize technological feasible reductions. By allowing every fuel to compete, and not excluding the fuels that we already know are highly polluting, the ARB will waste an incredible opportunity to truly push for a coordinated zero-carbon system, and protracts a lot of economic and political pain. In effect, ARB staff is picking winners and losers every day as they pick which values to employ among competing self-interests. For instance, the ISOR describes that in computing one input ARB staff and GTAP modelers assume that 25 percent of the carbon stored in the soil is released when land is cultivated. We *believe* this value is a *reasonable* compromise given the variability in data (emphasis added). This great scientific uncertainty and lack of metrics, objectives, or guidelines will create a free for all fuel situation with a long trail of stranded investments during initial uncertainties. When there are marginal differences in values between particular fuels on the Lookup Chart, we believe the ARB invites financial incentives for fraud, being flooded with opt-in values to get under the baseline, and the agency having to make a compromise situation, subject to competition from new fuel challengers. (CERA1)

Comment: CARB's failure to complete the LCFS rule before this adoption hearing places the regulated community and the public in an untenable situation. The missing elements of the rule (such as key carbon intensity (CI) values, and a mechanism for tracking and reconciling CI credits and debits) are so essential to the rule's functioning that it is not possible to assess the rule as a whole and comment upon whether its structure and approach are reasonable and workable, or determine whether compliance with the rule is feasible. (WSPA2)

Comment: To demonstrate the significance of gaps in the program at this point in time, we note the lack of several key carbon intensities for fuel pathways. Staff decided to construct two carbon intensity reduction silos at this point in time – one for gasoline and one for diesel (against our recommendation).

We are very concerned that ARB currently does not have any CI pathways completed for biodiesel, advanced renewable biodiesel or renewable diesel relative to the diesel silo. According to the scenarios developed by staff, these three fuels are supposed to provide 94%-100% of the diesel CI reductions, but we have no currency with which to formulate our plans for the program.

Similarly, for gasoline CI reductions, staff has not yet provided CI factors for cellulosic ethanol or advanced renewable ethanol, which our members need for compliance purposes. Electricity is expected to yield 9%-35% of the CI reductions required for gasoline, but ARB has not yet resolved how electric providers will participate.

When one combines this lack of CI's for these fuels with the lack of definition of regulated party on the electricity side, we are missing 90%-96% of the compliance pathway for the gasoline silo according to staff's scenarios. (WSPA1)

Response: Carbon intensities for several fuels likely to participate in the LCFS have been included in the Lookup Table. As for a mechanism to track the carbon intensity debits and credits, staff is working on creating a tool that would track these and also allow reporting to the Air Resources Board. Given that 2010 is a reporting year and not a compliance year, there is adequate time to test the reporting system and assist producers with compliance targets of the LCFS.

Early on in the regulatory process, the need to setup a separate gasoline and diesel standard was clearly explained to all stakeholders. As for fuels that will likely replace diesel, staff has published pathway documents using waste feedstock (Used Cooking Oil, Tallow) to biodiesel and renewable diesel. Staff is working to update the soyoil based biodiesel and renewable diesel pathways and will publish these soon for public comments. Additional fuel pathways such as algae derived biodiesel is also being considered for early 2010. Similarly, staff has provided estimates for carbon intensities for cellulosic ethanol from forest waste and farmed trees. As with diesel, staff is exploring additional feedstock-ethanol pathways to be developed in early 2010. As for electricity producers, they have the opt-in provision and actual procedures will have to be established once utilities (or other sources) approach ARB to request opt-in to the LCFS. The ISOR has also clearly pointed out that the regulated party for electricity providers is the power plant where the electricity comes from to California (see also the response to Comment K-134). Based on all the information provided, staff feels that WSPA has adequate information and data to design their industry compliance strategies.

K-201. Comment: An additional concern for is the relatively high energy efficiency for biomass based power production (i.e., 32% boiler efficiency for biomass as compared to 34% for natural gas). Biomass in general has a lower heating value because of higher moisture and oxygen contents, which means additional drying and higher feed rates are required. Both drying and higher feed rates will cause more process energy input and hence lower efficiency. In addition, additional

units will be needed for the removal of dirt and other impurities and NO_x reduction due to the presence of nitrogen fertilizers. The above mentioned and other technical feasibility issues in the use of biomass as boiler feed were not captured in the current draft. (CONOCO)

Response: In response to the Board's direction in Resolution 09-31, staff finished three biodiesel and three renewable diesel pathways. Thirteen pathways for natural gas and biogas as alternative fuels for diesel have been established. As a result, the Lookup Table for diesel and substitute fuels currently totals 24 pathways, not including the soy to biodiesel pathways. Staff are still developing the soy to biodiesel pathway, which will be submitted as a separate part of the rulemaking.

The LCFS does define how the electric providers will participate in section 95484. The section was modified by the Board to allow electric providers an option until 2015 to use estimates of the amount of electricity provided to vehicles in place of direct metering. The board, in Resolution 09-31, directed staff to work with the Public Utilities Commission (PUC), the CEC and other stakeholders to review provisions applicable to regulated parties for electricity. The Resolution also directed staff to further evaluate feasibility of generating credits for electricity in non-road transportation sources. It should be noted that the PUC has initiated a rulemaking to address its issues with regard to electric use as transportation fuel. When the PUC completes its rulemaking, ARB staff will review it to determine if adjustments are necessary to the LCFS and as appropriate recommend amendments.

With the inclusion of the Lookup Tables in the LCFS and the additional number of new significant pathways to both the gasoline and diesel tables, there are sufficient pathways established to allow compliance with the performance schedules. In addition, a key flexibility within the LCFS is the ability to add new subpathways or different pathways as they develop through Method 2A and 2B. This flexibility allows for advancement of technology to provide additional options for low CI alternative fuels and the ability to minimize costs through these advancements. New information regarding technological advances and economics are to be evaluated as part of the mandatory program reviews in 2011 and 2014.

See also comments and responses in FSOR Sections I, Economics, and J, Compliance Scenarios/Technology Assessment.

L. LAND USE CHANGE AND OTHER INDIRECT EFFECTS

This section contains comments specifically related to land use change. This includes comments pertaining to unavailability of land use change estimation methods; uncertainty of land use change emissions factors; exclusion of CRP and idle lands; crop yield adjustments; crop rotations of biofuels crops; individual yields and plant efficiencies; national vs. regional crop yields; and sensitivity to uncertain elasticity values; individual facility studies; complexity of land use change causation; land use change stifles current and next generation fuels; co-products and land use change; food vs. fuel; joint price elasticity of ethanol and DDGS; DDGS and livestock feed; other co-product issues; indirect effects only assessed against biofuels; fuel shuffling; the LCFS requires ARB to regulate land use; public availability of modeling data; ARB should proceed more slowly; other approaches to land use change estimation; positive effects of agricultural expansion; controlling land use change impacts; land use change impacts are greater than zero; dropping land use change stimulates high-carbon fuels; market innovation and second generation biofuels; ecosystem and biofuels effects; land use change and cattle production; direct land use change impacts; and land use change: other.

In addition to direct effects, some fuel production processes generate GHGs indirectly, via intermediate market mechanisms. If, for example, the propulsion system of an advanced vehicle requires a certain metal that is surfaced-mined in remote forested areas, the increased demand for that propulsion system would increase the demand for the required metal. Meeting that demand would result in the expansion of the mines that supply the ore for that metal. Expansion of the mines would require the clearing of forests, and the disturbance of underlying soils—both of which release GHGs to the atmosphere.

Stakeholders participating in the LCFS process have suggested that most or all transportation fuels generate varying levels of indirect GHG emissions. To date, however, ARB staff has only identified one indirect effect that generates significant quantities of GHGs: land use change effects. A land use change effect is initially triggered by a significant increase in the demand for a crop-based biofuel. When farmland devoted to food and feed production is diverted to the production of that biofuel crop, supplies of the displaced food and feed crops are reduced. Supply reductions cause prices to rise, which, in turn, stimulates increased production. If that production takes place on land formerly in non-agricultural uses, land use change impact results. The specific impact consists of the carbon released to the atmosphere from the lost cover vegetation and disturbed soils in the periods following the land use conversion.

Unavailability of Land Use Change Estimation Methods

This section addresses any comments arguing that the Board's land use estimates are immature, untested and inexact.

L-1. Comment: The currently available methods for estimating land use impacts are immature, untested, and inexact. As a result, they are too uncertain to be used in a public policy setting. The Global Trade Analysis Project (GTAP) model, which the Board has approved for use as a land-use change estimation tool, exemplifies the shortcomings of these methods. Due to the uncertainty inherent in the available estimation methods, indirect effects should not be included in LCFS carbon intensity values. (RFA2, NCB, A2ONESTE2, SHELL, CACA1, UCD2, BCC2, SUDERMAN, PE1, SUSCON, UCS1, JBI, WBIA, MCGA, UNE2, BP1, ACE, WSPA1, UNICA, CALSTART, NCGA, 111SCIENTISTS, NFA1, NCSU, BS, ILCORN, NFA2, CAC2, RFA1, CAPOZ, KLINE, WINNISON2, ABCINC, GE3, NBB, ABFA, MCSA, ABFA, CVAQ, USDGLLC, BIO, LEONARD, CO2STAR, VALENTE, ABENGOA, OCGA, NOVOSYM1, MDV1, TNSP, EDF2, IMC1, FORMLETTER5, CONOCO, ICM2, EESI1, PLS, PRX, ASUSA, COMF2, MONSANTO, IRELLC, AFBF, MDSA, PRIMAFUEL, BCC1, SHAFFER1)

Response: The Board acknowledged in Resolution 09-31 that the available methods for estimating indirect impacts (including land use change) are relatively new. As they continue to undergo development, the uncertainty associated with the impact estimates from these methods will decrease. In approving the LCFS, however, the Board found that current uncertainty levels are not sufficient to call into question the existence of significant indirect land use change impacts. The Board's position on indirect land use change impacts can be summarized as follows:

- a. Although challenging to estimate, increased production of biofuels does lead to significant land use change.
- b. Land use change does release significant quantities of sequestered carbon into the atmosphere.
- c. Because the LCFS is explicitly intended to reduce carbon emissions from transportation fuels in California, ARB cannot ignore the reality of land use change emissions. We must account for them in the lifecycle fuel analyses we perform. To do otherwise would be to underestimate the carbon emissions from biofuels, and to thereby send the wrong signals to those in the fuel industry who will be developing the next generations of low-carbon fuels.
- d. Though many commenters (UCD2, for example) urge the Board to base its indirect land use change analysis on actual land conversion (and related) data, neither the necessary data, nor the methods to analyze that data appear to be available at this time.¹⁵ While we agree with these commenters that the GTAP model cannot capture the dynamics of every instance of actual land use change everywhere in the world, it does have the ability to simulate a large proportion of the land use change known to occur as a result of rising commodity prices (see the response to Comment L-17, below, for further discussion of this point). Some of the difficulties associated with attempting to use actual land use change data for this purpose are described later by the comments under 'Complexity of Land

¹⁵ A variation on this theme occurred in a comment in letter ACE: Estimation of land use change should not be undertaken precisely because data on agriculturally driven land conversion is not available.

Use Change Causation'. These comments make the case that the causes of actual land use change are often numerous, complex, and interrelated. In some cases, it's not even possible to identify all the reasons a given tract was converted. In most, it is impossible to accurately weight all the causes behind a given conversion event. Some of those who submitted this comment cited a study appearing in *BioScience Magazine*¹⁶ to support their arguments. The Board agrees that—for the reasons cited in these comments—estimating the indirect land use change impacts of fuel production from actual land conversion data is not currently possible. That is why it is necessary to estimate these impacts using a model that faithfully captures and quantifies the overriding economic forces that drive land use change. Despite the complexity of the decision process behind conversion events, very few tracts are converted unless those responsible are convinced that the conversion will yield economic benefits. The Board's approach, therefore, is to use the most mature and highly regarded global economic model available—the GTAP—to estimate land use change impacts. The land conversion patterns the GTAP predicts are based on actual historical conversion patterns. Those historical patterns are described quantitatively, using empirical measurements of how conversion rates respond to commodity market price changes. The relationships in the causal link between commodity prices and land conversion are quantified using empirical data, to the extent that such data is available. Although it is true that commodity markets are complex (see RFA2), economists used empirical data to quantify the important relationships and transactions that drive these markets. Based on the resulting elasticities and coefficients, the model is able to simulate the market behaviors that drive the land use change process with sufficient accuracy.

- e. Biofuel-induced land-use change can occur as a primary impact (land is converted directly to biofuel crops), a secondary impact (biofuel crops displace other crops, which must be cultivated elsewhere), a tertiary impact (displaced crops displace other crops), and so on. As such, these impacts occur at many removes, both temporally and geographically, from the initial expansion of biofuel crop cultivation. The best economic model for estimating a system of outward-rippling impacts such as this is one that captures the relevant portions of all national economies likely to be affected by this process. The one model that has the scope and breadth to simulate such a system is the GTAP model.
- f. Not only is the scope of the GTAP model sufficient to estimate the relevant impacts, it is also a widely used, respected, and mature economic model. It has been used to analyze a number of large-scale economic changes worldwide over the last two decades. Although other models simulate the same economic effects the GTAP simulates, none have the GTAP's global scope. In sum, the GTAP is the best available tool for estimating the global land use change impacts associated with expanded biofuel production. When and if the Board is made aware of a better estimation tool, it can direct staff to utilize that tool.
- g. Many who object to the use of the GTAP argue that some of its predictions appear to be at odds with clearly observable trends in the real world. This is

¹⁶ Helmut J. Geist and Eric F. Lambin, "Proximate Causes and Underlying Driving Forces of Tropical Deforestation", *BioScience Magazine*, Volume 52, No. 2 (Feb. 2002)

seen as evidence of the failure of the model to accurately predict the outcomes of the increased demand for biofuels. The most often-cited example is the model's prediction that the allocation of larger proportions of the American corn crop to ethanol production would reduce American corn exports. USDA agricultural data show that corn exports have increased throughout the period in which ethanol production increased. These export increases in no way invalidate the GTAP's predictions. The USDA reports *aggregate* export data. Exports are influenced by a number of factors, including—but by no means limited to—the increased production of corn ethanol in the U.S. Some of those factors will tend to stimulate exports, while others will tend to depress them. The final, aggregate export numbers show only the net effect of all these factors. They are silent concerning the incremental contribution of any one factor. The GTAP, on the other hand, predicts *only* the incremental contribution of one factor (increased ethanol demand). Few would argue that the diversion of a significant proportion of the corn crop to domestic ethanol production would not reduce exports, if all else were held constant. The precise function of the GTAP is to estimate the incremental impact of this diversion of the corn crop, holding all else equal. All that can be said about the effect of this diversion on aggregate exports is that they are lower than they would have been in the absence of the diversion. The NRDC also recognized this point (NRDC3). A similar response can be made to comparisons between reported agricultural land area data and the GTAP's land use change predictions (PRX). The GTAP's land use change predictions are limited to the number of acres converted in response to an increase in American biofuel production. This prediction will have no discernable relationship to observed changes in aggregate crop acreages worldwide. Additional discussion of this point can be found in the response to Comment L-13, below.

- h. In order to prevent any model limitations from unacceptably skewing the land use change estimates used to create carbon intensity values under the LCFS, staff released the land use change estimates it produced for public comment. These estimates were discussed at various public workshops, and many written comments were submitted. Based on these comments, staff altered its model runs, and adjusted model outputs to reflect, for example, increasing crop yields. The NRDC (NRDC3) acknowledged the Board's efforts to solicit, respond to, and utilize comments. These revised estimates were as fair and equitable as possible, given the need to include such estimates in LCFS carbon intensities (as described above).
- i. The Board took immediate action in Resolution 09-31 to improve ARB's ability to estimate land use change impacts: it directed staff to convene an Expert Workgroup to thoroughly evaluate the estimation approach it has taken, as well as the available alternatives. The workgroup is to present its findings to the Board in the form of recommendations and proposed regulatory amendments. As with any large, complex model, however, the GTAP could be improved. Some of the improvements that would probably increase the precision of the GTAP's estimates are the following:
 - i. Predict on a dynamic rather than a static basis. The GTAP produces a single result based on a single changed condition (an increased demand for ethanol,

- for example), without respect for the time period over which the global economy returns to equilibrium following the introduction of the change. Equilibrium could return in less than a year, or over a period of several years. If the latter, it would be best if each year could be modeled individually (dynamically) using input parameters specific to that year.
- ii. Predict based on individual crops rather than aggregated crop groups: corn rather than coarse grains, soybeans rather than oilseeds, and so on.
 - iii. Expand the types of land areas available for conversion to agricultural uses. Former Conservation Reserve Program lands could be added in the U.S. Idle croplands that are not currently available could be added worldwide.

L-2. Comment: Indirect effects are not fully understood. Using estimates from a model that simulates an ill-understood process to establish regulatory carbon intensity values is inappropriate. The ability of the GTAP to accurately estimate the effect of domestic biofuel production on foreign land management practices and international agri-business investment decisions is suspect, for example. Other commenters (UCD2) doubt the ability of the model to characterize land use change in remote locations where land markets and property rights are dysfunctional. A common theme in this set of comments is that assumptions, beliefs, and anti-biofuel bias masquerade as findings in the Board's land use change decision. See responses to Comments L-11 and L-17 for a related discussion. (CALSTART, SUSCON, SUSCON, 111SCIENTISTS, RFA1, SUDERMAN, UCD2, UCD2, BCC2, BCC2, BCC2, PE1, PLS, ACE, ABUSA, GE3, AFBF, AFBF, ICM3, ICM3, CALSTART, NFA2, MDSA, MDSA, 111SCIENTISTS)

Response: In most respects, the processes that produce indirect impacts are well-understood. An indirect impact is simply the end result of a series of linked market events, all of which have been described by the principles of neoclassical economics, and measured empirically, as described in Chapter IV of the ISOR (the response to Comment L-17, below, contains a related discussion). The empirically derived values are used as coefficients and elasticities in various computable general equilibrium models, including the GTAP. An increase in the demand for corn ethanol, for example, stimulates an increase in the demand for corn. As demand increases, price increases. This price signal incentivizes farmers to produce more corn—either through intensifying their efforts in their existing corn fields, through the conversion of non-corn croplands to corn, or through expansion onto land not currently supporting crops. Because there is still a demand for the displaced crops, their price will rise, motivating farmers to increase the number of acres devoted to those crops (again, through intensification, displacement, or expansion). As this process results in the conversion of non-agricultural land into agricultural land, sequestered carbon is released into the atmosphere. Though this process is well-understood, estimating land conversion based on an assumed increase in demand presents unique challenges. The responses below discuss some of those challenges in more detail, as well as explain what the ARB has done, and will be doing, to arrive at reliable estimates.

L-3. Comment: GTAP results have not been validated against real world data. Computable general equilibrium (CGE) models in general have not fared well when their predictions have been tested against real world data. The values used in the GTAP don't correspond well with actual agricultural and corn ethanol production figures. CARB staff needs to understand and use these actual figures in its modeling. (SUSCON, AGBC, ILCORN, UNICA, JBI, RFA1, ACE, NOVOZYM1, MDV1, KLINE, WINNISON2, GE3, BIO, CACA1, NFA2, PRX, ABUSA, SHAFFER1)

Response: In general, validation of CGE model results is a difficult undertaking. The reasons for this are discussed in the responses to Comment L-1 and L-3: CGE models report only the specific, incremental effects of the change or perturbation being modeled (e.g., increased demand for biofuels). Real world data on very specific, incremental effects such as these almost never exists. In what may be an exception to this rule, the Illinois Corn Growers Association submitted a study of the land use change impacts of an increase in processing capacity at a single ethanol plant (ILCORN). Although this study found that the increased demand for corn created by the plant did not induce land use change, the study itself exemplifies the challenges faced by those attempting empirical land use change studies. Even though the study consisted of only the area within a 40-mile radius around the plant, a full accounting of the causes behind the observed cropping changes was apparently not possible. Corn acreage increased by 261,574 acres, while soybean acres decreased by 299,365. The researchers found these acreage changes were only partially caused by the ethanol plant's corn requirements, and that "other variables such as economics and high export demand may drive corn intensification." Potential effects beyond the study area were not discussed.

In general, data on exports, land conversion, caloric intake, trade volumes, etc. exist, but they consist of *aggregate* numbers: they reflect the net effect of many, often competing factors. The individual effect of any one factor usually cannot be teased out of them. The GTAP predicts that increased demand for ethanol will reduce corn and soybean exports, for example. The fact that aggregate corn and soybean exports actually rose over the period that was modeled is irrelevant. It just indicates that the factors tending to drive exports up (among them, rising meat consumption driving an increasing demand for livestock feed) tended to compensate for the downward pressure from the diversion of corn to ethanol production. Regardless of the actual aggregate trend in exports, it was lower than what it would have been in the absence of that diversion of the corn crop. The NRDC (NRDC3) also recognized this point. Despite these difficulties, however, the GTAP, unlike most other CGE models, has been subjected to validation studies. The results of these studies have been used to improve and refine the model.

L-4. Comment: Scientific consensus is lacking on the appropriate method for estimating land use change. The use of GTAP is controversial in the scientific community. Without additional scientific consensus, it is improper to include indirect land use change values in LCFS carbon intensities. (AGBC, NCB,

111SCIENTISTS, NCGA, JBI, MCGA, SUSCON, BP1, NOVOZYM1, MDV1, ABFA, USDGLLC, BIO, CACA1, UCD2, UCD2, BCC2, PE1, NFA2, CACA2, EESI1, MONSANTO, AFBF, JMBM, ICM2, ICM3, 111SCIENTISTS, KLINE, MDSA)

Response: Although there may not yet be a true scientific consensus on the appropriate method for estimating land use change, a number of highly regarded scientists have expressed their support for the approach taken by the Board (see comment letter 179SCIENTISTS, for example). Moreover, as discussed in the response to Comment L-1, the Board found that crop-based biofuel production does entail land use change impacts, and that those impacts do result in significant greenhouse gas emissions. In light of those findings, the Board determined that it would be remiss if it did not account for land use change impacts in the carbon intensities of crop-based biofuels. Acknowledging the uncertainty range around current LCFS land use change estimates, as well as the controversy those estimates have generated, the Board directed staff, in Resolution 09-31, to form an Expert Workgroup to continue studying the land use change phenomenon, and the available approaches to measuring it.

L-5. Comment: Computable General Equilibrium models such as the GTAP were not designed to estimate land use change or establish regulatory standards and should not be used for these purposes until they are validated for such use. Even the indirect effects they purport to measure have not been used as the basis for regulatory requirements prior to the LCFS. Complex predictive models such as the GTAP must undergo years of development before they are ready to be used for greenhouse gas regulation (The IPCC climate change model was cited as an example in comment letter ABCINC). The regulation should be based only on direct lifecycle effects until a sufficiently robust methodology for estimating indirect effects has been developed. (NFA1, NCB, SHELL, CALSTART, ILCORN, NCGA, JBI, MCGA, SUSCON, RFA1, ABCINC, ACE, WBIA, NOVOZYM1, MDV1, KLINE, ABFA, BIO, CO2STAR, 111SCIENTISTS)

Response: CGE models such as the GTAP were designed to estimate the impacts on the larger economy of significant changes in prevailing economic conditions. The types of changes CGE models have been used to evaluate vary widely: trade agreements, industrial expansion, logging operations, a wide variety of proposed public policy initiatives, etc. CGE models are often modified to allow them to be applied to new types of economic perturbations. The GTAP is not the only CGE model to have been extended to analyze the environmental implications of economic changes. The FASOM model (see Comment L-18, below), for example, has been extended to estimate various environmental impacts, including greenhouse gas generation. The U.S. EPA is using FASOM to evaluate the land use change impacts of the Energy Independence and Security Act (EISA). Because environmental impacts are largely an outgrowth of economic activity, using CGE models to estimate such impacts is not unusual. The appropriateness of the use of the GTAP to evaluate the land use change impacts of the LCFS is discussed the responses to Comments L-1, L-17, and other comments.

L-6. Comment: The uncertainty of estimating indirect land use change impacts prompted the European Union to postpone the inclusion of these impacts in its Renewable Energy and Fuels Quality Directive. (ABENGOA, NCGA, NOVOZYM1, UCD2, PE1, NFA2, ICM2)

Response: As other responses in this section acknowledge (see response to Comment L-1, and L-3), estimating the land use change impacts of fuel production pathways is a challenging undertaking. Despite these challenges, the Board concluded—unlike the European Union—that it would be remiss if it failed to account for this significant source of greenhouse gas emissions in its climate change regulations. In order to assure that its land use change estimates continue to benefit from the latest advances in estimation techniques and data availability, the Board directed the Executive Order to convene an Expert Workgroup to provide it with assistance in estimating land use change impacts. The Executive Officer is to coordinate this effort with the U.S. EPA, the European Union, and other entities pursuing a low carbon fuel standard (see Board Resolution 09-31).

L-7. Comment: A comprehensive, independent analysis of indirect effects and the available methods for estimating them should be undertaken as soon as possible. Some comments (NOVOZYM1, BIO) suggested that, in addition to an Expert Workgroup, the Board should await the results of the EPA's inquiry into indirect land use impacts, request the National Academy of Sciences to appoint a blue-ribbon panel to look into the issue, and coordinate with the European Union as it explores its options in this area. All indirect effect regulations should be delayed pending the conclusion of these inquiries. Including indirect land use change values in the regulation before a rigorous, consensus approach is developed could harm the fledgling biofuels industry. Indirect effect regulation at all levels (state, federal, and international) should be based on the same rigorous, widely accepted methodology. One comment (BIO) recommended that, during the methodology development period, the Board periodically publish non-binding best estimates of indirect land use change impacts. This would provide ongoing information to the investment community. Another comment (UCD2) stated that the purpose of the review process be to create an indirect land use change estimation method based on a comparison of approaches, including the direct evaluation of actual land use change events. (CALSTART, ILCORN, LEONARD, EDF2, JBI, MCGA, ABCINC, WSPA1, BP1, WBIA, BP1, NOVOZYM1, ABFA, BIO, RFA2, CACA1, UCD2, BCC2, ICM3, CERA1, SCAQMD1)

Response: The Board agrees that the issue of land use change impact estimation must be subject to ongoing evaluation and analysis. In order to assure that this evaluation and analysis takes place, the Board directed staff to convene an Expert Workgroup to carry it out. The Board also concluded, however, that (1) because land use change impacts are significant, it would be remiss if it did not account for them in the LCFS, and (2) staff's land use change estimates are sufficiently robust (and have

been sufficiently vetted) to justify their inclusion in LCFS. Given the need to act quickly to control climate change (as articulated in Executive Order S-01-07, in which Governor Schwarzenegger directed the Board to create an LCFS), the Board determined that it cannot wait for either the federal government or the European Union to decide on how to approach the problem of assessing land use impacts. Moreover, the federal and European fuels programs differ from the LCFS in that they set biofuel production targets. The LCFS, on the other hand, is performance-based: it does not require the production of specific volumes of designated fuels. Given this difference, there is no compelling reason to strongly link the LCFS to either program. Despite these differences, the Board did direct the Executive Officer to coordinate the work of the Expert Workgroup with similar efforts underway at the U.S. EPA, the European Union, and other entities pursuing a low carbon fuel standard.

L-8. Comment: At least some of the land use change impacts assigned to biofuels by the GTAP could be caused by other factors. As the price of oil increases, for example, the price of commodities like corn and soybeans also rise. This causes increased planting of these more valuable commodities. This means that at least some of the land use change attributed to biofuels is actually due to oil price increases. Other factors such as world economic conditions and trade policy can also have an effect. (ILCORN, PRX, UIUC1)

Response: The GTAP is designed to isolate the independent effects of a carefully specified change to a single factor—an increase in the demand for corn ethanol, for example. All other economic conditions, such as changes in the price of oil—are held constant. Although the overall increase in the prices of commodities like corn and soybeans are the net result of a number of factors, the GTAP holds all except the single factor of interest constant. While in no way denying that some commodity prices are related to the price of oil, therefore, the GTAP land use change results for corn ethanol are in no way skewed by that (or any other) relationship.

L-9. Comment: The controversy generated by ARB's decision to include land use change impacts in the LCFS regulation has needlessly slowed the approval process down. It has also eroded support for the regulation. (JBI)

Response: It is not clear that the LCFS approval process would have proceeded any more quickly had the Board decided to defer consideration of land use change impacts. The constituency urging the Board to account for land use change in the LCFS regulation—like the constituency urging deferral—is large, active, well-informed, and well-funded. If consideration of land use change impacts had been deferred, the objections from that quarter would have slowed the approval process down about as much as the objections of those arguing for deferral are currently impeding it. Moreover, the speed of the approval process is not the overriding consideration. As discussed in the responses to comments L-1, L-4, L-6, and L-7, the Board concluded that land use change impacts are a significant source of greenhouse gas emissions, and must be accounted for in the LCFS. In order to assure that its land use change estimates continue to benefit from the latest advances in estimation techniques and

data availability, the Board directed staff in Resolution 09-31 to convene an Expert Workgroup to thoroughly evaluate the estimation approach it has taken, as well as the available alternatives to that approach.

L-10. Comment: One source of uncertainty and inaccuracy in the GTAP estimates is the model's inability to account for the implementation of policies designed to protect sustainability. Such policies would reduce or prevent the conversion of lands that sequester significant amounts of carbon to agricultural uses. (KLINE, BIO, ACE)

Response: In a policy designed to begin the urgent process of slowing climate change, it would be imprudent to assume that future land use change decision-making would depart significantly from historical practices. This is not to say that the Board does not fully support and encourage the widest possible adoption of policies designed to encourage sustainable land use practices. To date, however, there is little evidence that such policies are having a significant impact on land use change patterns globally. The prudent course for the Board to take under these conditions is to assume that history is the best predictor of the future. This is, in fact, a guiding principle in the design of the GTAP model. If compelling evidence comes to light indicating that sustainability practices are, in fact, influencing land use change decisions, the Expert Workgroup convened in response to Board Resolution 09-31 will consider that evidence, and recommend modifications to existing land use change estimation procedures, as warranted.

For more details on sustainability, please see Section G of this FSOR.

L-11. Comment: The indirect land use change process behind the GTAP analysis is only a hypothesis, and the land use change estimates the model produces are only theoretical. (KLINE, PRX, ABUSA, MONSANTO, JMBM, PE2) As such, those estimates don't pass the "rules of reason" tests established in Federal case law for assessing indirect impacts. (KLINE)

Response: While it is correct that the indirect land use change process is not currently subject to direct observation, a large body of evidence provides strong support to the existence of a land use change process that is both real and significant. Based on this body of evidence, the Board has concluded that it is appropriate and justifiable to estimate the indirect impacts of fuels whose feedstocks displace food, feed, and fiber crops in significant quantities. The legitimacy of the Board's approach to estimating the magnitude of land use change impacts is discussed in response to Comment L-1, as well as to Comment L-17, below. The commenter who alluded to case law which establishes a "rules of reason" test for evaluating indirect impacts (KLINE) did not provide citations to the applicable cases. We cannot, therefore, determine the applicability of that case law to the LCFS. The commenter does list six considerations which "may help answer the 'rule of reason' question." The Board feels that—apart from the case law questions to which we are unable to respond—the approach taken to

LCFS land use change analysis is reasonable when evaluated against these criteria. The criteria, along with the Board's responses to each, are as follows:

- a. Are estimated ILUC impacts speculative within the context of all the other events, circumstances and contingencies that exist to enable the effect (e.g. deforestation)?
The conversion of non-agricultural land to agricultural uses in response to rising commodity prices is not mere speculation: it is a process that has strong empirical backing and widespread acceptance in the scientific community. The developers of the GTAP simply quantified the well-understood relationships (elasticities and coefficients) that drive this process, and built them into the model. The model, therefore, produces predictions that are consistent with well-understood and often-observed historical behaviors. See the response to Comment L-1 for additional discussion of the basis of the Board's land use change modeling.
- b. Is the impact (loss of natural habitat/deforestation) inevitable, independent of the proposed action and the theorized indirect impacts?
Based on historical rates of loss of grassland and forest to agriculture in response to increases in commodity prices, the predictions of the GTAP are certainly inevitable, within a reasonable margin of error.
- c. Does the "precautionary principle" clearly favor one proposed action over another? (e.g., What are the impacts on land use change and deforestation if less biofuels are accepted under LCFS due to the assumed ILUC factors?)
The dire consequences of uncontrolled climate change have been described in detail by many respected climate scientists. Given that land use change is a significant source of greenhouse gases, and that land use change is an inevitable result of increased biofuel production, the precautionary principle clearly favors reasonable action to account for land use change emissions in a regulation designed to reduce greenhouse gas emissions.
- d. Is the estimated impact increasingly tenuous as inquiry extends outward from the core project area?
The "core project area" for the production of corn ethanol under the LCFS is quite large: it covers those areas in the U.S. that produce corn for the production of ethanol. Moreover, land use change rates are calculated similarly, regardless of geographic location. As such, the uncertainty ranges around land use change estimates don't vary with distance from a core area.
- e. If there is a "reasonably foreseeable" indirect impact, does it occur in a remote locale that is not under direct U.S. control?
The Board has determined that an increase in ethanol production from 1.75 to 15 billion gallons per year would require the conversion of about 3.89 million hectares from non-agricultural uses to agricultural production worldwide. Of that total, 2.33 million hectares would occur outside of the U.S.
- f. What is the "legally relevant cause" of the impact? (Is the ILUC impact isolated from the proposed action?)
The legally relevant cause of the impact, in the case of biofuels regulated under the LCFS, is the increased production of crop-based biofuels in the U.S.

L-12. Comment: The standard methodologies for calculating carbon intensities ignore indirect emissions. They also credit some fuels with emissions savings based on the co-products created during the fuel production process. This is not a true accounting of fuel greenhouse gas impacts. (CAPOZ, FORMLETTER5)

Response: The Board recognized that existing lifecycle analysis models did not account to the indirect impacts, including indirect land use impacts. That is why it authorized the use of a supplemental model (currently, the GTAP) to estimate indirect land use change impacts. The estimates from that model are being added to fuel carbon intensity values, as appropriate. The Board has also committed to an ongoing inquiry into the best indirect land use change estimation methodologies. Accounting for co-products in lifecycle analysis is not controversial. Fuel co-products that displace other products that involve greenhouse emissions should be appropriately credited in the lifecycle analysis.

L-13. Comment: An indication of the inadequacy of the GTAP is that it predicts a decline in food consumption resulting from reduced food crop and livestock availability and increased food prices. According to the United Nations Food and Agriculture Organization (FAO), per-capita caloric intake rose to record highs when the GTAP predicted declines (RFA2). Similarly, the model predicted a loss of 10 million acres of U.S. forests due to an increase in ethanol demand. Between 2001 and 2006, U.S. forest acreage increased by 0.6 percent. (NFA2, MONSANTO, RFA2). Another apparent discrepancy is between the increase in land devoted to the major row crops (around 142 million acres, as reported by the USDA) and the increase predicted by the GTAP Model (closer to 10 million acres). (PRX)

Response: The response to Comments L-1 and L-3 discusses the relationship between aggregate export data, and the specific predictions of the GTAP model. The same relationship holds between (1) aggregate per-capita caloric intake and the model's prediction of reduced food consumption in response to food prices and supplies, and (2) actual versus predicted changes in forest cover. Aggregated caloric intake is driven by multiple factors. Increased food prices and decreased supplies are only two of those factors. Some factors push caloric intake up, while others bring it down. The aggregate intake number reflects the net effect of all these factors. It is silent on the relative contributions of each. Over the period covered by the FAO's report, factors that drove caloric intake up—such as rising affluence in China and India—had a larger influence on the aggregate food consumption than factors which drove consumption down—such as decreased supplies and higher prices. The GTAP, on the other hand, predicts *only* the incremental effect of one factor—decreased supplies and higher prices caused by the diversion of an increased proportion of the corn crop to ethanol production. This is not a prediction of decreased *aggregate* consumption. It predicts only the incremental contribution of one factor. This prediction can also be understood as a decrease in consumption, *holding all other factors constant*. It should also be noted that reduced food supplies and increased prices affect

the world's poor disproportionately. Those who can afford to pay higher food prices will generally do so, as needed to sustain or increase consumption over time. Those who cannot afford higher prices for food often have little choice but to reduce consumption.

In a similar manner, the increase in forest cover cited by the commenter (NFA2) is an aggregate number, reflecting the net effect of all factors influencing forest cover trends. The change predicted by the GTAP, on the other hand, is the independent, incremental effect of a single factor—increased demand for corn ethanol. That change is what we'd expect to see if all other factors affecting changes in forest cover could be held constant (the ISOR reports a predicted forest cover decrease of 43 million acres due to an increase in ethanol production of 13.25 billion gallons. We are not aware of a 10 million acre GTAP prediction). What actually occurred between 2001 and 2006, however, was that the factors causing forest cover to increase had a larger influence on the aggregate cover change than did the factors causing forest cover to decline. We can say, however, that modest increase in forest cover reported for the 2001-2006 period is less than it would have been in the absence of an increasing diversion of corn to ethanol production.

The same line of reasoning applies to the difference between total world agricultural land use conversion, and the GTAP's land use conversion prediction: The GTAP only predicts the incremental conversion attributable to increased ethanol production.

L-14. Comment: The use of indirect land use change factors in the LCFS could affect agricultural land use, economic and climate change policies in other jurisdictions. The adverse impact of the LCFS could be similar to that of a publication entitled *Livestock's Long Shadow* published by the United Nations' Food and Agriculture Organization. The indirect land use change impacts attributed to livestock raising may be appropriate in places like Brazil and Indonesia, but they are clearly not appropriate for American livestock operations. (CACA1, CACA2, ICM2)

Response: States seeking to implement their own climate change policies are currently studying the LCFS to gauge the extent to which it might serve as a template for those policies. If some or all of those states decide to follow California's example by including indirect land use change factors in fuel carbon intensities, then the LCFS will have influenced climate change policy. As the responses to Comments L-1, L-4, L-6, and L-7 indicate, the Board feels that the indirect land use change estimates currently in the LCFS lookup table are reasonable. For this reason, we feel that it is appropriate and beneficial for the LCFS to exert an influence on developing low carbon fuel standards elsewhere. The likelihood for the LCFS to influence federal climate change policy appears to be somewhat lower at present. The Federal Renewable Fuel Standard sets quotas for the production of corn ethanol. These quotas essentially guarantee corn ethanol a market share for the foreseeable future. Insofar as the LCFS does influence climate change policy in other jurisdictions, however, the market for crop-based biofuels could be expected to decrease over time. This would reduce demand for corn, soybeans, and other crops used to produce biofuels. In terms of climate change, however, this is a desirable outcome: as the demand for these biofuels

decreases, the release of carbon dioxide from the conversion of non-agricultural lands to agricultural uses will also decrease. Although we won't be responding to the comment about the Food and Agriculture Organization's *Livestock's Long Shadow* raised in this LCFS comment, we are committed to refining our indirect land use change estimates for the LCFS on an ongoing basis, using the best available data and estimation techniques. We are confident that our current, very reasonable estimates will only become more tenable over time.

L-15. Comment: The ARB appears to be moving more slowly with its indirect land use change estimates for diesel substitutes than with its estimates for gasoline substitutes. Why can't the Board move equally slowly and carefully with its estimates for both categories of fuel substitutes? (CACA1)

Response: The Board is taking the same approach to its indirect land use change estimates for both gasoline and diesel substitutes. Our approach to diesel substitutes only appears to be on a slower track. The reasons behind this appearance are twofold: (1) Staff began its indirect land use change analysis with gasoline rather than diesel substitutes. The available information indicated that, because the crop-based ethanol market is larger than the soy biodiesel market, it made sense to begin our indirect land use change analysis with ethanol. (2) The soy biodiesel analysis faced two complications that were not faced in the ethanol analysis. First, soybeans could only be analyzed as part of the general oilseeds crop group. Staff felt that the oilseeds group is not an adequate proxy for soybeans, due to differences in yields and other parameters. Second, the soy biodiesel co-products situation is more complex than the comparable ethanol situation.

L-16. Comment: A balanced, science-based LCFS could reduce dependence on foreign petroleum (a national security issue), slow climate change, and bring new opportunities to the agricultural sector. Biofuels are an important part of the national economy, and would be instrumental in hastening a recovery (or even saving the U.S. from an economic collapse from which it might not recover). As currently configured (i.e., with current land use change estimates), the LCFS would have the opposite effect. Adding a land use change increment to the carbon intensity of corn ethanol will have the effect of undermining the only currently available clean alternative to petroleum. (CACA1, ICM1, EESI1, JMBM, ICM3, BCC2, BCC1)

Response: The Board agrees that the model used to estimate indirect land use change impacts, as well as the estimates themselves, should be subjected to ongoing analysis and refinement. In order to facilitate this review process, the Board directed staff in Resolution 09-31 to form an Expert Workgroup to conduct the necessary review. In doing so, however, the Board did not reject staff's current land use change estimates. For the reasons articulated in the response to Comment L-1 in this section, and echoed in several subsequent responses, those estimates were deemed to be reasonable. By approving the carbon intensity values in the current version of the fuel pathway lookup table, the Board expressed its finding that those values reflect the best available

information from both the research community and from the comments received on the draft low carbon fuel standard (the regulation and the ISOR). Because the Board views those values as reasonable approximations of actual carbon intensities, those values, by definition create the incentive structure needed to ensure that the LCFS achieves its primary goal of a ten percent reduction in fuel carbon intensity by the year 2020. Those incentives will provide crop-based biofuels with a substantial share of the California fuel market until lower-carbon fuels can be brought to market in sufficient quantities. As this primary goal is met, the secondary goal of reducing the State's dependence on imported petroleum will also be met. The incentive structure created by the existing fuel pathways may or may not create new opportunities for the agricultural sector, or other sectors of the American economy. The creation of such opportunities, however, was never a goal of the LCFS.

L-17. Comment: GTAP does not *discover* land use change, in any empirical sense. Instead, the diversion of crops and cropland to biofuel feedstocks is *assumed* to cause land use change, and that assumption is built into the model. The model, therefore, faithfully infers land use change as a consequence of increased biofuel demand. This is more a case of anti-biofuel bias masquerading as science than it is true science. Even if is the best tool available (as CARB asserts), we have no evidence that its predictions are accurate. As such, it is an unacceptable way to create a regulatory “penalty” against a class of fuels. (UCD2, BCC2, EES11, ABUSA, MONSANTO, JMBM, PE2, MDSA, PRX)

Response: The assertion that the causal connection between increased demand for agricultural commodities and land use change is merely an assumption or a hypothesis is patently incorrect. The empirical evidence that farmers respond to higher prices by increasing their production of the higher-priced commodity is abundant. Depending upon the size of the price signal, some farmers will increase production by converting new land to cropland—a response that has also been frequently observed, documented, and measured (The NRDC (NRDC3) reinforces this conclusion). The conversion of non-agricultural land to agricultural uses in response to rising commodity prices is not a convenient assumption or a mere bias: it is a process that has strong empirical backing and widespread acceptance in the scientific community. The developers of the GTAP simply quantified the well-understood relationships (elasticities and coefficients) that drive this process, and built them into the model. The model, therefore, produces predictions that are consistent with well-understood and often observed historical behaviors. To assert that the GTAP simply operationalizes the biases of modelers and regulators is to ignore the strong historical and empirical basis of the relationships captured in the model. See the response to Comment L-1 for further discussion of this point.

L-18. Comment: The U.S. Environmental Protection Agency decided against using the GTAP in its analysis of the land use change impacts of the Federal Renewable Fuels Standard. (NFA2)

Response: Although the U.S. EPA chose not to use the GTAP model to estimate the land use change impacts of the Renewable Fuels Standard, it did not decide (like the European Union) to defer consideration of land use change impacts, pending methodological improvements. Importantly, the approach the U.S. EPA took to land use change analysis is very similar to the approach taken by the Board. That approach consisted of linking an economic optimization model of the American agricultural and forestry sectors (the Forest and Agricultural Sector Optimization Model (FASOM)) with an economic model of the world agricultural sector (the Food and Agricultural Policy Research Institute (FAPRI) model). These linked models analyze the impacts of increased biofuel production in much the same way the GTAP does: the disequilibrium introduced by an increase in biofuel demand is allowed to ripple through the sectors included in both models until a new equilibrium is reached. This system of models, like the GTAP, predicts significant land use change impacts from the increased diversion of corn to ethanol production. Despite the different models used, and the different fuel policies analyzed, the overall approaches are quite consistent—as are the results. The U.S. EPA’s decision is in no way a repudiation of the GTAP or the results it produces.

L-19. Comment: The GTAP cannot make accurate predictions because it does not account for a number of relevant factors, such as policy shifts, the weather, world economic conditions, and other economic, social, and political factors. (NFA2)

Response: The GTAP was intentionally designed to calculate estimates based on long-term, average conditions without considering short-term aberrations from the norm. In general, estimates that are grounded in long-term conditions have more relevance to policy than those associated with transient departures from the norm. Another problem with short-term, volatile conditions is that they tend to be unpredictable in both duration and magnitude. Rather than attempting to control for a host of volatile and unpredictable political, social, meteorological, and economic conditions, therefore, the GTAP assumes that all such factors are constant at their more stable long-term average values. Only the parameter of interest—biofuel demand, for example—is varied. The resulting estimates tend to have greater relevance for the longer term.

L-20. Comment: The GTAP does not account for the latest information regarding the high carbon absorption potential of energy crops. If, using scientifically rigorous models or analysis, Staff determines that certain biofuel pathways have a net land use change benefit, i.e., they will sequester more carbon than they emit through land-use change, the Board should consider early adoption of regulations that lock-in these net benefits for these “best technologies.” The early recognition of these net benefits of “best technologies” should drive the evolution of the biofuels industry towards such technologies. Later, after the requisite period for scientific studies, the Board can consider adoption of final regulations that fix land use change penalties for “lagging technologies.” (NFA2, BIO, 111SCIENTISTS)

Response: The carbon sequestration capacity of an energy crop is a direct rather than an indirect effect. As such, it would be accounted for in the Board’s lifecycle analysis

model, CA-GREET, rather than in GTAP. CA-GREET currently treats energy crops as having a net carbon absorption capacity of zero: the carbon that is absorbed during the crop's growth cycle is released during harvest, processing, and subsequent fuel use. If credible published research demonstrates that a fuel crop sequesters significant amounts of carbon, the fuel producer can submit that information to the Board as part of an application for a new fuel pathway. The LCFS regulation provides regulated parties (fuel producers and importers) with a process for requesting that the Board create new fuel pathways (see Section 95486(c)). This process was created specifically for regulated parties whose fuels are less carbon intensive than the closest equivalent fuels in the LCFS Lookup Table.

L-21. Comment: Nitrous oxide emissions from the use of nitrogen fertilizer and legume monocultures are a significant source of carbon emissions. These sources have not been accounted for in the Board's land use change analysis. (2619, FORMLETTER5)

Response: The Board agrees that the use of nitrogen fertilizers may be a significant source of greenhouse gas emissions. As such, staff will be reviewing the available data and exploring potential methods for including this emissions source in the land use change analysis. We are not aware of the significance of legume monocultures to the land use change analysis, but invite interested parties to provide us with relevant information on this subject.

L-22. Comment: Land use change is an ongoing process. If forest and grassland is not converted to agriculture in response to an expanding biofuel industry, it is still subject to urban expansion, industrial uses, logging and livestock operations, and many other forms of degradation. Given our inability to know what the fate of converted lands would have been in the absence of the expansion of biofuels production, it is not appropriate to attribute the loss of those lands to the biofuel industry. If land is converted to agriculture in response to an increased demand for biofuels, but it ends up growing a biofuel crop, that conversion should be counted as a carbon credit rather than a debit. (PLS, CONOCO, STAUB)

Response: The GTAP estimates the amount of land converted in response to a specific increase in biofuel production. It does not attempt to adjust that estimate to account for the probability that the converted land would have been converted for other reasons in the absence of pressure from the biofuel industry. This is an entirely legitimate approach. The biofuel-driven pressure to convert grassland and forest to agriculture augments the existing set of land use change pressures. As such, more land will be converted in the presence of pressure from the biofuels industry than in the absence of that pressure. The GTAP simply estimates that conversion increment attributable to biofuel expansion. In addition, the land use change estimated by the GTAP is restricted to the land needed to replace displaced food, feed, and fiber crops. The planting of biofuel crops on newly converted agricultural land in response to an increase in the prices paid for those crops is, technically, a direct impact. Such plantings are considered to be a direct response to price, rather than an indirect

response to displaced food, feed, and fiber crops. Conoco (in letter “CONONCO”) also stated that a baseline year is not specified in the Board’s analysis. The baseline year, as stated in the ISOR, is 2010.

L-23. Comment: If it is to yield credible results, a model that estimates the land use change impacts associated with a specific causal factor must be capable of isolating only the land use change driven by that single factor. To attribute land use change driven by other factors to the factor being modeled would be inappropriate. (ACE)

Response: The GTAP is designed to estimate only the land use change attributable to a single cause. The primary design elements responsible for restricting land use change estimates to the specific cause of interest are the elasticities the model uses to define the various market relationships at work in the model. Elasticities are values that define how an effect responds to a cause—how, for example, an increase in the price of corn stimulates farmers to more intensively cultivate their corn crops in order to realize higher yields. Elasticity values are established based on the best data from the relevant literature. The overall effect of various cause and effect relationships quantified in GTAP is that the total land requirement (the number of hectares needed to replace the hectares diverted to biofuel production) is reduced to reflect higher yields; reduced demand for the higher-priced commodity in the food, livestock feed and export markets; the co-product effect, in which fuel production co-products displace other products that generate greenhouse gases; as well as other effects. In the case of corn ethanol, each hectare of corn diverted to ethanol production ends up creating the need for only about a third of a hectare of new farmland, worldwide.

L-24. Comment: CARB must resolve the uncertainty over how the impact of land use change will be factored in to the carbon intensity calculation for biofuel pathways. (3095, Shell)

Response: The Board has approved the method described in the LCFS ISOR for incrementing direct fuel carbon intensities to account for land use change impacts. That method involves using the GTAP model to determine the amount and location of new agricultural land required, calculating the greenhouse gas emissions from the conversion of that land, and then converting those emissions into the standard carbon intensity units of gCO₂e/MJ. This conversion is accomplished by annualizing total emissions over a 30-year time horizon. For a full description of this approach, please see Chapter IV of the ISOR.

L-25. Comment: AIR, Inc. released a study showing that increasing corn ethanol production to projected 2015 levels (the same levels modeled by ARB staff) resulted in no indirect land use impacts. This result was mainly due to the use of greater co-product credits and higher crop yields. (AFBF, PE1)

Response: The results reported in the AIR, Inc. study were obtained using input values (primarily co-product and yield values) that the Board considers to be outside of the

range of reasonable, defensible values. These values, along with all aspects of our land use change analysis will, however, be carefully evaluated by an Expert Workgroup, to be convened as directed in Board Resolution 09-31.

L-26. Comment: At the April 23, 2009 Board hearing, Dr. Tom Hertel, who initiated the development of, and continues to oversee, the GTAP model, stated that “if he were King Solomon he would just use these numbers [sic]. That's 17 not 30.” (PE2; these are the commenter's, not Dr. Hertel's, words)

Response: Dr. Hertel's exact words were, “there are those who focused on the environmental side who've argued that we're overstating the yield response and that the land area conversion should be larger. And those on the industry side have focused on a different parameter relating to yields . . . if I were King Solomon, I might say "I'll give you both what you wish for." And as it turns out, it doesn't change the results dramatically, because these are offsetting effects.” Dr. Hertel does go on to acknowledge the uncertainty present in estimates from the GTAP. The issue of uncertainty is taken up in the responses to Comments L-1, L-2, L-4, L-5, L-6, and other responses in this section.

L-27. Comment: Typographical errors were present in the spreadsheets and write-ups presented for public review. The definitions of some terms used were also unclear (“total energy use” and “total energy,” for example). In addition, the number of significant figures used in reported carbon intensity values varied within and between documents. These must be corrected and/or clarified. (CONOCO)

Response: See the response to Comment K-149 (“Lifecycle Analysis”).

L-28. Comment: The preliminary land use change impact values for vegetable oils have adversely affected the California biodiesel industry. Although the values reported in the ISOR were not official, and were not included in the LCFS lookup table, they have unfavorably influenced investment decisions. They have communicated to the fuel industry that vegetable oil biodiesel is not likely to be a viable low carbon fuel. In addition, the expectation expressed in the ISOR that advanced biodiesel will provide the needed low carbon diesel fuel may prove unrealistic. Advanced biodiesel may not become commercially available in the volumes specified in the ISOR. This would put the regulation ahead of commercial realities. (COMF3, COMF2)

Response: Another set of land use change values for oilseed crops will be released for comment in late 2009. The values released in the ISOR were clearly identified as preliminary, so as not to unduly influence investment decisions. In calculating these and other fuel carbon intensities, the Board's goal is to accurately capture the significant direct and indirect lifecycle emissions of each fuel. By assuring that all carbon intensity values are as comprehensive and accurate as possible, the Board furthers its goal of incentivizing the development of lower carbon fuels. As these fuels are identified and

developed, they will replace higher carbon fuels in the marketplace. As a performance-based regulation, the LCFS is not designed to promote or protect specific fuels.

L-29. Comment: We question the assignment of the same land use change carbon intensities to all types of ethanol, and urge CARB to determine the specific carbon intensity of each fuel pathway. (SHELL)

Comment: Feedstock specific ILUC impacts – Advanced biofuels should not simply be assigned the same ILUC factor as corn ethanol. The ILUC factor should be specific to the feedstock source and how it was grown. In general, advanced biofuels should have much lower ILUC impacts than corn ethanol. In some cases, a zero impact should be credited for example, a biofuel derived from waste materials (EE1)

Response: ARB staff temporarily assigned all ethanol fuels the same land use change carbon intensity for illustrative purposes in an early LCFS workshop. Staff has since calculated a specific land use change value for corn ethanol and sugarcane ethanol, and is working on specific values for some forms of cellulosic ethanol. As part of the rulemaking, ARB staff committed to release specific values for the various vegetable oil biodiesel fuels. The values are expected to be released after the first of the year.

Uncertainty of Land Use Change Emission Factors

L-30. Comment: The Woods Hole Research Center emission factors used by the GTAP to calculate GHG emissions are too uncertain. They are averaged over too wide a geographic area which renders them inaccurate for many specific locations. Published data on emissions from land clearing vary widely. One commenter (UIC3) questions whether the land use change emissions the GTAP predicts are credible if the error associated with the emission factor data set exceeds the rate of change associated with biofuel introduction. Emission factor error ranges must be accounted for in the GTAP's GHG emissions estimates. If no formal quantitative adjustments for the emission factor error rate are possible, the land use change factor assigned to biofuels should be conservative. (UIC3, Leonard, UNICA, NFA1, ACE, SHELL, VALENTE, CERA2, ACE)

Response: The Woods Hole Research Center emission factors were compiled so that projected future land use change would occur primarily in regions and in ecosystem types that experienced agricultural land use conversion during the 1990s. Projected land use change was allocated to these regions in proportion to the amount of change that each experienced during the 90s. This approach allows conversion projections to follow established historical patterns. To date, the Board has seen no compelling data indicating that future patterns are likely to depart significantly from observable historical trends.

Data on historical land use conversion trends were compiled from a variety of region-specific sources—The Food and Agricultural Organization Forest Resources

Assessment, for example. The Woods Hole data is grouped into ten regions. For use with the GTAP model, that data was re-categorized into 18 agro-ecological zones. Within each zone, emission rates are reported by ecosystem type. For each ecosystem type in each region, emission factors (annual metric tons of carbon per hectare) are derived from the available empirical data. The regional emission factors used in the GTAP consist of the weighted average of all ecosystem types within each region. Land use change emissions are calculated by multiplying the number of hectares converted to agriculture in each agro-ecological zone by the corresponding emissions factor, and then summing over all converted land areas. The variance, or error, associated the Woods Hole emission factors is not reported in the literature describing the construction of those factors.

Although it is based on the best currently available empirical data, emissions factors are averaged over extensive geographical areas. Emission factors specific to smaller geographic areas (and with known error rates) would be preferable. As improved factors meeting these requirements become available, the Board will base its land use change emissions estimates on those factors. The Board is convening an Expert Workgroup to consider possible approaches to improving its land use change estimates. Parties with potentially useful emission factor data should submit that information to the Expert Workgroup. In the meantime, the Board has adopted a conservative (low) land use change carbon intensity increment for ethanol from corn, pending the development of estimation methods that yield greater precision overall.

L-31. Comment: Emissions estimates from forest lands don't appear to have been adjusted to account for the fact that not all the carbon in the cleared woody material is released to the atmosphere during the year following the clearing. Some is used for building material and continues to sequester carbon for two or more years after the clearing event. The necessary adjustment is made using what is known as a 'storage derating factor.' (RFA1, NRDC3)

Response: We agree that a mistake was made in the Staff Report's description of the emission factors used for modeling land use change. However, the mistake does not result in a downgrading of the 30 g/MJ value to 28.3 g/MJ. Instead, the mistake calls for correcting the assumption shown in the Staff Report, as discussed below. This typographical error in the Staff Report will be corrected in an errata to the Staff Report. However, for the reasons discussed below, this mistake ultimately did not affect the 30 g/MJ and 46 g/MJ values for the "Land Use or Other Indirect Effect" entries shown for the "Ethanol from Corn" and "Ethanol from Sugarcane" pathways, respectively, listed in Table 6 of section 95486(b)(1).

A miscommunication between ARB, UC Berkeley, and Purdue resulted in a discrepancy between the emission factors discussed in the Staff Report (and presented on the ARB website) and the emission factors actually used in the land use change modeling for the regulation. The following statements were made in the Staff Report based on this miscommunication:

- “In applying the Woods Hole emission factors, ARB assumed that 90 percent of the above-ground and 25 percent of the below-ground carbon is emitted over the fuel production period (50-52).” (Page IV-21)
- “Our current modeling assumes 90 percent of the above ground carbon is released to the atmosphere following land conversion.” (Page IV-46)

Instead of “90 percent,” the actual assumption was “100 percent.” Accordingly, staff intend to make the following corrections in an errata to reflect the actual assumption used in the modeling:

1. “In applying the Woods Hole emission factors, ARB assumed that 90 percent of the above-ground and 25 percent of the below-ground carbon is emitted over the fuel production period (50-52).”

will be changed to read:

“In applying the Woods Hole emission factors, ARB assumed that 100 percent of the above-ground and 25 percent of the below-ground carbon is emitted over the fuel production period (50-52).”

2. “Our current modeling assumes 90 percent of the above ground carbon is released to the atmosphere following land conversion.”

will be changed to read:

“Our current modeling assumes 100 percent of the above ground carbon is released to the atmosphere following land conversion.”

While the “90 percent” assumption is mistakenly shown in the Staff Report, the regulation approved by the Board with modifications actually incorporates a “100 percent” assumption. That is, the Board approved land-use change carbon-intensity values of 30 gCO₂/MJ for corn ethanol and 46 gCO₂/MJ for sugarcane ethanol, which are based on the assumption that 100 percent of the above-ground carbon is released to the atmosphere following land conversion and not 90 percent as stated in the staff report.

As stated in the Staff Report on page IV-46, we recognize the validity of the argument that when forests are converted to cropland, some of the above ground biomass will be converted to wood products, paper, and other consumer goods. The carbon in these items will continue to be stored while these products are used, and, in many cases, after they have been deposited in landfills. However, as also stated in the Staff Report on the same page, decay of biomass in landfills will more likely lead to release of methane (a more potent GHG) rather than carbon dioxide. This would have to be considered if a non-trivial percentage of biomass from converted lands is placed in landfills.

We also note that the emission factors used to calculate the carbon intensity of 28.3 gCO₂/MJ mentioned in the comment are incorrect. These emission factors assume 90 percent of above ground carbon from both forests and grasslands is released to the atmosphere following land conversion. It is not appropriate to assume 10 percent of grasslands biomass will end up in wood products, paper or other consumer goods and thereby not be released to the atmosphere.

The ARB staff continues to analyze this complex issue to determine the most appropriate percentage of above and below ground carbon that is released to the atmosphere. In recognition of the complexity of this and other issues relevant to land use change calculations, the Board directed the staff in Resolution 09-31 to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. The Executive Officer was directed to return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified through the Expert Workgroup.

L-32. Comment: The Woods Hole Research Center emission factors used in the GTAP to calculate GHG emissions do not account for the N₂O emissions from the application of nitrogen fertilizers to agricultural lands. (VALENTE, UCS3, CERA2)

Response: The Board agrees that N₂O emissions must be accounted for in land use change emissions. We are currently working to include this important source of emissions into our land use change carbon intensity calculations.

L-33. Comment : Land use change emission factors must account for any carbon sequestration gained when land is converted to agricultural uses. Some conversions that may increase sequestration are the conversion of pasture to cropland, and the conversion of degraded lands to switchgrass cultivation. If, using scientifically rigorous models or analysis, staff determines that certain biofuel pathways have a net ILUC benefit, i.e., they will sequester more carbon than they emit through land-use change, the Board should consider early adoption of regulations that lock-in these net benefits for these “best technologies.” The early recognition of these net benefits of “best technologies” should drive the evolution of the biofuels industry towards such technologies. Later, after the requisite period for scientific studies, the Board can consider adoption of final regulations that fix ILUC penalties for “lagging technologies.” (UNICA, DUPONT1, BIO)

Response: The carbon sequestration capacity of an energy crop is a direct rather than an indirect effect. As such, it would be accounted for in the Board’s lifecycle analysis model, CA-GREET, rather than in GTAP. CA-GREET currently treats energy crops as having a net carbon absorption capacity of zero: the carbon that is absorbed during the crop’s growth cycle is released during harvest, processing, and subsequent fuel use. If credible published research demonstrates that a fuel crop sequesters significant

amounts of carbon, the fuel producer can submit that information to the Board as part of an application for a new fuel pathway. The LCFS regulation provides regulated parties (fuel producers and importers) with a process for requesting that the Board create new fuel pathways (see Section 95486(c)). This process was created specifically for regulated parties whose fuels are less carbon intensive than the closest equivalent fuels in the LCFS Lookup Table.

L-34. Comment: The ISOR is not clear on how the GTAP utilizes the Woods Hole Research Center emission factors to calculate land use change emissions. (RFA1)

Response: The ISOR provides a brief overview of how the GTAP utilizes the Woods Hole emission factors on pages IV-18, IV-19, and IV-21. Additional details are provided above in the response to Comment L-30.

L-35. Comment: The GTAP should account for increases in the extent of forested land. (UNICA)

Response: Land use changes unrelated to the expansion of biofuel crops (such as increases in the extent of forested land) are exogenous to the system being analyzed. Exogenous factors are held constant in a GTAP analysis. If a GTAP analysis finds land use change does occur following an expansion in biofuel production, the most that can be said about exogenous factors, like the extent of forested land, is that they are incrementally affected by the biofuel-driven land use change. An ongoing exogenous increase in forested land, for example, may be slowed, but not reversed, by the effects of the biofuel crop expansion (this issue is more extensively covered in the responses to the comments in the category entitled “Unavailability of Land Use Change Estimation Methods.” See the response Comment L-13, for example.).

L-36. Comment: The GTAP results were largely similar to those released by another researcher using the FAPRI model. It is not surprising that the two models reached similar conclusions: they used the same emission factors – a single set of data from the 1990s – for both exercises, without any apparent additional analysis or verification. Other land use emissions studies have shown a tenfold difference in land conversion emissions depending on what assumptions are used. (NFA1)

Response: We can’t be sure which FAPRI-based research the commenter is referring to, but it may be the Renewable Fuels Standard analysis prepared by the U.S. EPA (FAPRI is the acronym for “Food and Agricultural Policy Research Institute”). It is partially correct that the corn ethanol land use change analyses prepared by the U.S. EPA and the ARB used similar emission factors. While the ARB used the Woods Hole factors with very little modification, the U.S. EPA retained Winrock International to substantially modify those factors for inclusion in the FAPRI analysis. Although the use of similar emission factors alone wouldn’t predispose two such analyses to arrive at similar results, we would expect two analyses of the same phenomenon to arrive at

similar conclusions if both are carefully designed and well-executed. Although different models were used, both employed similar analytical approaches. The similar results achieved, therefore, are due more to other factors than they are to the use of similar emission factors.

L-37. Comment: CARB'S analysis of the carbon intensity of switchgrass appears to be flawed. It seems to use the carbon debt value for the conversion of grasslands to corn for ethanol, arbitrarily apply a 25 percent factor to estimate conversion to switchgrass production. It is more likely that grasslands or marginal lands would be converted to switchgrass production, resulting in emissions similar to what is described by Fargione et. al. in the February 2008 Science paper describing the conversion of abandoned cropland to prairie biomass ethanol. In addition to the Fargione paper, there are several existing studies on switchgrass production which show switchgrass production as a GHG sink rather than a source (e.g., Liebig et. al. 2007; Adler P. 2007; Schmer et. al. 2008). (DUPONT1)

Comment: We are also greatly concerned by the ISOR's premature presentation of insufficient and questionable analysis on the land use change impacts of cellulosic feedstocks. In the ISOR, cellulosic crop-based biofuels are assumed to induce indirect land use change emissions of 18 g CO₂-eq./MJ. There is very little research and virtually no modeling to support this initial conclusion. In fact, ARB's indirect land use change assessment for cellulosic biofuels relies almost entirely on a few pages of information from an unpublished, un-reviewed paper by Purdue University researchers. The Purdue authors themselves characterize the analysis as a "very rough picture" of the potential land impacts of cellulosic feedstocks. While ARB characterizes the cellulosic indirect land use change value as preliminary in nature, publishing the result at all will establish a view of cellulosic biofuels that may be significantly disconnected from reality. We also question ARB's selection and use of specific assumptions. For example, ARB assumes average cellulosic feedstock ethanol yields will be 250 gallons/acre. Published literature and data from field trials suggest commercial-scale ethanol yields will be much higher. (ABENGOA)

Response: The switchgrass analysis appearing in the ISOR was very preliminary. The Board is currently working on a more definitive analysis of cellulosic fuels, including switchgrass. We will consider the research showing that switchgrass can serve as a net carbon sink. As the response to Comment L-33, above, indicates, our current practice is to assume that any carbon fixed by a fuel crop is released as the crop is harvested, processed, and used. This assumption may not apply to perennial crops like switchgrass. If not, we will adjust our analysis accordingly.

L-38. Comment: The Governor's Office of Planning and Research is seeking to amend the California Environmental Act (CEQA) guidelines to require environmental impact reports to include estimates of a project's expected carbon intensity, and to require mitigation measures should that carbon intensity exceed

a predetermined threshold. Anthropogenic emissions and emissions associated with direct land use change (e.g. converting forests or rangeland which are sinks to a carbon source) can be measured accurately using current scientific methods. However, applying an indirect land use model to the CEQA permitting process would present significant challenges to those seeking or requiring a permit and could require industry to unjustifiably constrain production due to emissions perceived to be associated with indirect land use change. (CACA1)

Response: This rulemaking focuses solely on the land use change impacts of fuel production and use as they affect the assigned carbon intensities of fuels subject to the LCFS. It has no direct effect on actions the Office of Planning and Research may take regarding CEQA guidelines on addressing the GHG emissions of projects subject to CEQA. We recommend that you provide the Office of Planning and Research with a copy of the letter containing this comment.

Exclusion of CRP and Idle Lands

L-39. Comment: In addition to omitting CRP land, the GTAP model also does not include idle land and cropland pasture. These land sources are significant (NCGA).

Comment: There seems to be a lack of consistency in the LUC evaluation. It appears that CRP, idle land, and cropland pasture land sources are available for use by cellulosic feedstocks in the model, but not available for corn-based ethanol in the land use change assessment (NCGA).

Comment: The GTAP model does not include inputs for idle or CRP lands. This is a concern for two obvious reasons: (1) idle lands will be the first to be converted under any reasonable land conversion scenario; and, (2) any model that does not include idle and CRP land will produce exaggerated forest effects because the major points of domestic agricultural land use expansion are disabled. Lands in developing countries without clear rents (economic values in a marketplace) cannot be analyzed in GTAP. This includes much one-time cropland that is not accounted for or included in the GTAP estimates of effects. The preliminary ILUC numbers reviewed to date have been described as robust by several researchers involved, but an analysis that does not include the major points of domestic and international agricultural land expansion is not robust. (NFA1)

Comment: Both the set-aside program in Europe and the Conservation Reserve Program in the U.S. have been major sources of agricultural land coming into the production of biofuels. The European set-aside program kept 9.4 million acres of land idle in 2007 through farmer subsidies for not producing, but in the fall of 2007 the set-aside program was suspended for at least one year to free up idle land for agricultural production in the face of high commodity prices (Waterfield, 2007). In 2008, the set-aside program was abolished permanently, although

European farmers will still receive the subsidies even though they can now use the land for commercial production (Wikipedia, 2009). The U.S. Conservation Reserve Program had a net loss of 2.1 million enrolled acres between 2007 and 2008 and an additional loss of 1 million enrolled acres between 2008 and 2009 (USDA, 2009). The 3.1 million acres have been put back into agricultural production. Further, the acreage cap on the Conservation Reserve Program was reduced in the 2008 Farm Bill from 39.2 to 32 million acres by 2010, thus freeing up additional agricultural land. These programs have acted as a buffer stock of agricultural land and have helped to mitigate indirect land use changes for the production of corn ethanol in the past few years. Given the slowing demand for ethanol and the excess capacity in the ethanol industry, coupled with idled agricultural land, any further non-agricultural land use change attributable to corn-based ethanol should be minimal. (NCSU)

Comment: The GTAP model used by CARB to assess land use impacts provides a limited basis on which to fully judge the impact of the LCFS. This model does not take Conservation Resource Program (CRP) land into account, for example. This past summer, the USDA allowed 24 million acres of CRP land - previously held as pasture land - to be converted to crop production to support the growing demand for corn ethanol in light of the floods which occurred during this summer in Iowa and surrounding areas. The conversion of untilled soil (pasture land, fallow land, etc) to corn production can result in a dramatic increase in carbon emissions, as there is twice as much carbon "sequestered" in soil than in the atmosphere. This incremental acreage utilization effect can inevitably lead to some increase in soil carbon emissions which had been "sequestered" for decades if not centuries. Large incremental changes in demand for agricultural land can therefore have real and lasting impacts. Understanding the GHG implications of these changes is essential, given the fuel volumes under consideration under the LCFS. AQMD staff recommend that, as part of future LCFS refinements, these factors be reflected both in the GREET and GTAP modeling done to analyze various compliance path options under the LCFS. (SCAQMD1)

Comment: It can be expected that many land use changes associated with biofuels will involve the use of existing agricultural lands that are either idled or damaged. Additionally, biofuel crops can be grown on marginal lands, which may involve land use changes. (LEONARD)

Comment: Missing land sets in the GTAP database result in extra forest land being converted - The analysis does not consider relative costs of converting different land types, resulting in overestimation of forest land converted. (RFA1)

Comment: For the improved U.S. land use database, we assumed that only grasslands were converted in the U.S. The current GTAP model used by CARB omits Conservation Reserve Program (CRP) land, idle land, and cropland pasture. If these land types were included in the model, the amount of forest

converted would be much lower. CARB included this additional land case in their June 30 workshop results, but it was omitted without explanation from the ISOR. (RFA1)

Comment: Missing land sets in the GTAP database result in too much forest land being converted. The GTAP land database does not include Conservation Reserve Program (CRP) lands. Also, as a part of developing the indirect land use change emissions values for cellulosic ethanol, Purdue identified two new land categories that are not in the GTAP inventory – cropland pasture and idle land. (RFA1)

Comment: It is particularly troubling to us that the current model runs for indirect land use change do not include inputs for the use of marginal and idle land. The omission of these land types is problematic because any grower who is looking to produce biofuel feedstock will look to idle and marginal land in order not to disrupt current cash flows. A land use assessment without this factor is quite simply not credible or based on real world decision-making (OCGA).

Comment: Omission of Idle Land and Cropland Pasture. In addition to omitting CRP land, the GTAP model also does not include idle land and cropland pasture. As a part of its assessment of cellulosic land use impacts, Purdue University examined these land sources as possible land for cellulosic feedstocks. These land sources are very significant. Purdue estimates there are 14.7 mha of idle land and 22.7 mha of cropland pasture. Together, this is more than twice as much land as in the current CRP (about 14.9 mha). Perhaps not all of these lands would support crops, but a significant portion of them probably would. If these land sources were added to GTAP, the amount of forest converted would be even less than if just the CRP land were added to GTAP. (RFA1)

Comment: The analysis does not consider relative costs of converting different land types, resulting in overestimation of forest land converted. (RFA1)

Comment: On page IV-41, the statement is made, "If sufficient CRP land is not available to indirectly support an expansion of corn acreage, a large supply of non-CRP pasture land that was formerly in crops could be brought back into production." It is not clear what the term "indirectly support" means; Congress has recently reduced the permitted acreage for enrollment in the CRP. More importantly, the assertion of the existence of "a large supply on non-CRP pasture land that was formerly in crops" is not quantified or supported with USDA or Ag Census data. The CARB staff should note that present pasture land (in its full extent) is used for pasturing. There is no "large" and unused reserve of pasture available for energy crops, independently of economic interaction with all other types of food and feed cropland. (PRX)

Comment: It is particularly troubling to AFBF that the current model runs for indirect land use change do not include inputs for the use of land enrolled in the

Conservation Reserve Program (CRP) and idle cropland. The omission of CRP and idle land is problematic because any farmer looking to produce additional biofuel feedstock is most likely to look first to idle cropland so as not to disrupt current cash flows. A land use assessment without this factor is quite simply not credible or based on real world decision-making. (AFBF)

Comment: Many other items are still missing, for example, the model does not include approximately 35 million acres of Conservation Resource Protection (CRP) Land, and 24.9 million acres of “idle” land. Until these major land areas in the U.S. are included in the model, its predictions of land use change are highly suspect. Other issues that are of concern will be discussed below. (RFA1)

Comment: Even at this late stage in the LCFS process, the GTAP model runs still do not reflect basic on-the-ground realities, such as the use of marginal and idle lands. (111SCIENTISTS).

Comment: The model also does not include carbon rich public lands in developing countries that are under some of the most severe conversion pressure. Inclusion of these lands is likely to greatly increase the emissions from indirect land-use change. (NRDC3)

Response: The Board acknowledged in Resolution 09-31 that estimating indirect impacts including land use is challenging, using currently available methods. The Board states that the LCFS regulation approved was developed using the best available economic and scientific information. We agree that there needs to be further work to characterize in greater detail the land use types that are subject to conversion by the GTAP model, such as Conservation Reserve Program (CRP) land, idle and fallow cropland. One can generally refer to these as surplus croplands. There are efforts currently by many institutions and GTAP researchers to include these types of lands in the GTAP database. Once such a database becomes available, we will evaluate it for possible adoption. Many of the commenters above agree that that more land is needed to meet future biofuel demand and that suppliers can increase production by using the so called surplus croplands. On the other hand, the same commenters claim that the amount of additional land needed for biofuels production will either be negligible or zero. The fact is that there is no surplus cropland that can produce biofuels without some land use change impacts.¹⁷ Many current research efforts confirm that there are likely to be significant pressure on increasing agricultural lands due to population increases and rising incomes of India and China. Biofuels demand magnifies this pressure further by competing with best available lands against food crop production. The current trends in crop yield increases can dampen the need for more available land, but the overall effect is increases in land use. What is considered surplus croplands comes in and out of production every so many years due to fluctuations in crop prices. If the lands were truly surplus, they would revert to grassland or forest and therefore gain carbon. In

¹⁷ Searchinger, Timothy, et al., “Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land Use Change”, Science Magazine, February 7, 2008, pp.13-14. www.sciencemag.org/cgi/content/full/1151861/DC1

essence, there is no surplus cropland that can produce biofuels without some land use change impacts. In this regard, the Board has directed staff to convene an Expert Workgroup to evaluate the indirect land use impacts parameters. It further directs staff to report the results of the Expert Workgroup findings to the Board by December 2010.

Crop Yield Adjustments

L-40. Comment: The method used to estimate effects of exogenous yield trends overestimates land use changes. (RFA1)

Comment: The biofuels “shock” implemented in GTAP is inconsistent with USDA projected crop yields. (RFA1)

Comment: Concern with GTAP: inconsistency of projected average grain yields and the period of the “shock”. (RFA1)

Comment: Models such as GTAP, while useful in initiating a discussion about ILUC impacts and values, are simply not complex enough to accurately determine how various biofuel feedstocks will affect land use decisions worldwide and, therefore, should not be the basis for a regulatory action. From oversimplifying the myriad of elasticity factors that affect land-use decisions to underestimating the importance of global yield improvements over time, the existing models represent more of a starting point for the conversation but cannot be counted upon to provide accurate ILUC carbon impacts for a given fuel feedstock. (ABFA)

Comment: The 13.25 bgy ethanol shock applied to the GTAP model to estimate land use effects simulates the ethanol volume from 2000/01 to 2015/16. Over this period, the USDA indicates yields will increase 23.4%, from 136.9 bu/acre in 2000/2001 to 169 bu/acre in 2015/16. In making the exogenous yield adjustment, ARB is going only from 2001 to a 2006-2008 average yield. This is inconsistent with the years of the ethanol shock. (RFA1)

Comment: This also suggests ARB’s best estimate of average corn grain yields in 2015 is that they will be unchanged from 2006-08. What are the specific reasons for the belief that yields will not continue to increase after 2006-08? (RFA1)

Comment: What are the impacts on the land use changes if yields go significantly higher, as indicated by the recent USDA projections? At a minimum, ARB should perform a sensitivity analysis of the land use impacts to this assumption. (RFA1)

Comment: We are not sure how ARB arrived at 9.5% (even if the average yield for 2006/07-2008/09 is weighted based on acres harvested and total production for each respective year, the weighted average is still 151.3 bu/acre—a 10.5%

increase over 2000/01). In any case, this is not critically important because we believe ARB should use the USDA projection of a 23.4% increase from 2000/01 to 2015/16 to be consistent with the ethanol shock implemented in GTAP. (RFA1)

Comment: It is important to note that U.S. farming practices continue to advance both in sustainability and productivity. According to the United States Department of Agriculture (USDA), in 2008 American farmers produced the second largest corn crop on record and attained the second highest yield per acre in history with fewer energy and fertilizer inputs. (AFBF)

Comment: We assume that the 30 g CO₂eq./MJ land use change emissions estimate that ARB presented on January 30 utilizes the exogenous yield adjustment. Therefore, the base level that ARB started with in the absence of the exogenous yield adjustment is 32.8 g/MJ (30/0.913). A 23.4% improvement in yield would reduce the LUC by 19%, so a 19% reduction of 32.8 is 6.2 g/MJ. Thus, accounting for 2015 projected yields would reduce corn ethanol LUC emissions by 6.2 to 26.6 g/MJ. (RFA1)

Comment: ARB proposes to estimate the exogenous yield increase (as in the previous section), and estimate the percent reduction in land converted directly from this exogenous yield increase, and apply the percent reduction to the land use change emissions. For example, ARB estimates the increase in yield from 2001 to 2006-08 at 9.5%. The reduction in land use emissions is therefore $1/1.095 = 0.913$ which corresponds to an 8.7% decrease ($1 - 0.913 = 0.087$). ARB estimates that, without an exogenous yield improvement, 3.9 mha in the world will be converted from either forest or grass to crops because of the ethanol increase to 15 bgy. The new land use change total after the exogenous yield adjustment would be 3.57 mha ($3.9 * 0.913$). The reduction in land converted is therefore .33 mha ($3.9 - 3.57$ mha). There are major problems with this adjustment, which is conducted external to the model. One is that the yield adjustment is only applied to the area of converted land, and not to all land growing corn. There are implicit assumptions in the method that the increase in exogenous yield on the current land (worldwide) is balancing demand, and that the rate of increase in yield outside the U.S. is the same as the rate of increase in within the U.S. All of these are untested assumptions. (RFA1)

Comment: Related to this, the ARB adjustment method breaks down severely at significantly higher yield levels. And, if it breaks down at higher yields, then it is also inappropriate at lower yield increase levels. To illustrate this, suppose hypothetically that a technological breakthrough allowed corn yields worldwide to double overnight. The USDA estimates that worldwide, corn production in 2007/08 was 786 million metric tons of corn. So, a doubling of yields and the use of the same amount of land worldwide would produce twice as much corn, or 1,572 million metric tons of corn. Approximately 131 million metric tons of corn will be needed to produce 15 bgy of ethanol in 2015, so the amount needed for

15 bgy is much less than the amount that the doubling of yields would produce (131 mmt is roughly 17% of 786 mmt). Certainly, this additional supply would be more than enough to take care of any increase in demand for corn for non-fuel needs and for the 15 bgy in the U.S., so there would be no need to convert any new land to crops for the 15 bgy. However, using the ARB yield adjustment method, the reduction in land use change resulting from a doubling of yield is only 50%, from 3.9 mha to 1.95 mha, for the 15 bgy scenario. This exercise demonstrates the pitfalls associated with this yield adjustment method. (RFA1)

Comment: There is an incorrect assertion in Appendix C10 (pp. C-44 and C-47) that yield increases have been the same across countries and major crops since 2001; therefore, ARB incorrectly assumes a simple adjustment external to the GTAP model is appropriate to account for the significant increase in U.S. corn yields since 2001. Per Table 1 below, growth rates in corn yields have differed between the U.S. and the rest of the world (ROW); moreover, there has been a particularly notable difference in the growth rate of other crop yields versus U.S. corn. From 2001 through 2007, U.S. corn yields increased at an annual average rate of 1.5%, whereas ROW corn yields increased at a 2.0% rate; thus the ROW growth rate was 1.4 times that of the U.S. Including preliminary yield estimates for 2008, ROW corn yields increased 2.2% annually from the 2001 base year to the average for the period 2006-2008, or 1.5 times the increase in U.S. corn yields. As acknowledged by the authors of the appendix, "If U.S. corn yield grows slower than ROW yield, then we will overestimate the net change in cropland due to increase in ethanol production" (RFA1)

Comment: The differential in growth rates versus yields of other commodities, specifically soybeans, is of particular importance in determining real-world crop area allocation in response to a demand shock. From 2001 to 2007, soybean yields increased at an average annual rate of 0.9% in the U.S. and 1.2% in the ROW; these rates were only 0.6 and 0.8 times the U.S. corn yield growth rate, respectively. (Data for Table 1 were obtained from the USDA's Production, Supply & Distribution database; though it is recognized that the GTAP model utilizes data from the U.N. Food and Agriculture Organization, it is doubtful there would be a significant difference.) (RFA1)

Comment: In reality, while U.S. corn yields did increase by 9.5% during this time period, ROW corn yields increased by 14.2% (refer again to Table 1). Using the factor $1/(1+\text{percent change in corn yield}/100)$, the amount of land required would be: $47/(1+0.142) = 41$ Mha. Thus, the reduction in land required due to yield improvements should have been 6 million hectares (47 Mha - 41 Mha), which is a 50% greater reduction than the 4 million hectares (47 Mha - 43 Mha) from the GTAP authors' example. This indicates that the land use adjustment that was performed outside the GTAP model might have been inadequate; that is, the adjusted results from the model might still have overstated the amount of land use change associated with an increase in ethanol production. (RFA1)

Comment: The results for corn are not as dramatic as those for soybeans, since the expansion in area has not been as large in percentage terms, but area and yield patterns for corn point in the same direction as those for soybeans. Both U.S. and non-U.S. corn area grew by roughly one-fifth between the 1989-1991 period and the 2006-2008 period. Over that timeframe, yields increased by approximately one-third. Additionally, the increases outside the U.S. have been slightly higher than those for the U.S.: non-U.S. yields increased 34% on an area increase of 22%, while U.S. yields rose by 32% on an area expansion of 18%. (RFA1)

Comment: It is likely problematic that the GTAP model takes cross-commodity effects into account, but the subsequent adjustment outside the model does not. In a manner related to the previous two comments, the assumptions (stated or implicit) in Appendices C5 and C10 that all yield increases have been similar, which allows an adjustment to be made outside the model rather than having all acreage allocation and impact estimates made inside the model, are problematic. (RFA1)

Comment: In particular, the extent to which corn versus soybean area is assumed to increase in the ROW in response to a shock to U.S. corn demand is important. On average over the last three years, U.S. corn yields have been approximately 2.55 times ROW corn yields, whereas U.S. soybean yields have been a lesser 1.25 times ROW soybean yields (i.e., half the magnitude of the corn differential). Thus, if corn area increases in the U.S. at the expense of soybean acres, and additional soybean acres in the ROW are needed to make up for a loss of U.S. soybean acres, the land-use impact will be less than if corn were to account for a large share of the ROW area change. Given the comments above regarding the elasticities discussed in Appendix C5, it is not clear that the model “handled” this issue appropriately. (RFA1)

Comment: An additional factor that will prevent further land use changes attributable to the production of corn for ethanol is the impressive increases in corn yields being realized now and expected in the future. Monsanto Company has projected a doubling of corn and soybean yields from their 2000 levels by 2030 and Edgerton (2009) and Eathington (2007) make it clear that, with new biotechnology traits and molecular marker-assisted breeding, there is a high likelihood that Monsanto’s goals will be reached, further solidifying the lack of need for additional land. Nearer-term projections are that average corn yield will increase to 180 bushels per acre by 2015 (Schlicher, 2008). In addition to the yield increases, strides are being made to increase the ethanol yield from each bushel of corn. Today that yield is 2.8 gallons per bushel, as is mentioned above. Ethanol yield is expected to increase to 3.3 gallons per bushel in 2015, mainly because of the further development of corn hybrids expressly for ethanol production (Schlicher, 2008). (NCSU)

Comment: Although the average corn yield was changed to reflect the 2006-2008 average in the Air Resources Board's analysis using the GTAP model, no account has been taken of the future yield increases that the advanced corn and soybean biotechnologies will provide. For example, the new triple stack corn hybrids and the newer hybrids containing multiple modes of action for various types of insect pests will be available commercially in 2009. In addition, higher yielding biotech soybean varieties, such as Roundup Ready® 2 Yield, are now being introduced. These innovations, coupled with molecular marker-assisted breeding techniques, should increase average corn and soybean yields in the U.S. by a substantial amount as these new technologies are adopted. (NCSU)

Comment: As a starting point, any analysis must correctly identify the direct implications of the amount of U.S. corn acreage that will be needed to meet the mandated level of renewable biofuels production by 2015. Starting with the annual mandates of use through 2015, assuming that those mandates will be met primarily by corn production, and assuming a continuation of the current average yield of ethanol per bushel of corn (2.86 gallons per bushel based on a recent study conducted at the University of Nebraska¹), the amount of corn needed for each corn marketing year through 2015-16 can be calculated. Those calculations are shown in Figure 1 (attached). Corn use for ethanol production in 2008-09 is projected at 3.7 billion bushels by the USDA and 5.2 billion bushels would be needed in 2015-16 to meet the mandate of 15 billion gallons. Next, the acreage of corn needed to meet the production level implied by the mandate can be calculated based on an assessment of the likely average yield of corn each year to 2015. As indicated in Figure 2, the U.S. average corn yield has trended higher in a linear fashion since 1960. The trend increase has been 1.87 bushels per acre per year. Many believe that average yield will show a steeper trend in the future. However, a continuation of the current trend results in a calculated trend yield of 164.3 bushels per acre by 2015. (UIUC¹)

Comment: Further, tremendous increases in grain output per unit of land coupled with growing supplies of animal feed co-products, like distillers grains, have essentially eliminated the need to expand global cropland base in response to increased U.S. biofuels production. It is also notable that despite the predictions of some supporters of the indirect land use concept, exports of grains and oil seeds from the U.S. have not declined appreciably and, in fact, last year we saw record exports of both corn and soybeans from the United States even in light of record ethanol production. (RFA²)

Comment: Figure 2 illustrates how the ILUC value should decrease as soy bean yield increases. (A2O4NESTE²)

Comment: I have found the land-use charge for biofuels issue to be one of the most frustrating. The vast majority of public opinion appears to be passionately shaped by old outdated studies that fail to account for the significant shifts in

technology achieved in recent years, or it's simply based on long-held assumptions that color one's interpretation of the facts. (SUDERMAN)

Comment: I won't take your time to review the facts, as I see from comments already submitted that the biofuels industry has done an excellent job of detailing changes in model results that accurately reflect the facts that I've been able to uncover. I urge you to carefully consider this data from highly respected models that have been updated in the past couple of years to reflect current technology. (SUDERMAN)

Comment: CARB report does not appear to provide a sensitivity for changing ratios of US and rest-of-world yields. CARB is possibly overestimating the net change in cropland and land use change. If agricultural products are more valuable, the use of more advanced farming techniques are likely to be adopted in parts of the rest-of-world. This would lead to a much faster percent increase in yields in rest-of-world compared to the US. In the US, improved corn yields from existing acres in the past 25 years have resulted in corn production that would have required an additional 150 million planted acres had yields not steadily improved. In essence, better yield has created 150 million "virtual acres", almost double the corn acres harvested every year in the US. The advent of ethanol and other biofuels over this same period has been accommodated by these production improvements, and not been shown to cause land conversion as a way to make up for reduced food or feed supplies – in fact, US exports of both corn and soy have remained stable or increased over the years. In the developing world, where concerns about adequate food and feed supplies are even more urgent, these productivity improvements lag far behind. Yields in sub-Saharan Africa, for example, are only about 20 percent of US yields. While a 5X improvement may not be realistic or appropriate worldwide, increasing the value of agricultural products can support the adoption of more advanced farming techniques, leading to faster increases in yields, and the possibility of addressing food needs, land use, and alternative fuel development – without hastily discounting the potential of biofuels as one solution to these complex challenges. (DUPONT1)

Comment: We recently obtained a copy of a letter signed by over 100 scientific experts from universities and national labs across the country, including members of the National Academy of Sciences who make a compelling case for fully understanding the implications and basis for an "indirect" land use penalty against biofuels. Given the recent scientists' letter, it seems clear that there is a lack of scientific consensus and understanding in regard to "indirect" effects for all fuels and that the model being used has not been validated and tested against real world data, including yield increases over time, feed displacement from products such as distiller grains and actual market responses. (AGBC)

Comment: The CARB report does not appear to provide a sensitivity for changing ratios of US and rest-of-world yields. CARB is possibly overestimating

the net change in cropland and land use change. If agricultural products are more valuable, the use of more advanced farming techniques are likely to be adopted in parts of the rest-of-world. This would lead to a much faster percent increase in yields in rest-of-world compared to the US. In the US, improved corn yields from existing acres in the past 25 years have resulted in corn production that would have required an additional 150 million planted acres had yields not steadily improved. In essence, better yield has created 150 million “virtual acres,” almost double the corn acres harvested every year in the US. The advent of ethanol and other biofuels over this same period has been accommodated by these production improvements, and not been shown to cause land conversion as a way to make up for reduced food or feed supplies – in fact, US exports of both corn and soy have remained stable or increased over the years. In the developing world, where concerns about adequate food and feed supplies are even more urgent, these productivity improvements lag far behind. Yields in sub-Saharan Africa, for example, are only about 20% of US yields. While a 5X improvement may not be realistic or appropriate worldwide, increasing the value of agricultural products can support the adoption of more advanced farming techniques, leading to faster increases in yields, and the possibility of addressing food needs, land use, and alternative fuel development – without hastily discounting the potential of biofuels as one solution to these complex challenges. (DUPONT)

Comment: We fully respect the science based rule-setting procedure, and accept the CGE model and that of GTAP as being appropriate. However, I have several concerns in some of the assumptions, notably those related to yields, growth rates and regional differences. Specifically, the analysis does not include higher yields that are coming from new technology and thus significant new land may not be needed to meet our feed, food and fuel needs during the period in question. (NDSU)

Comment: Yield levels (and growth rates) vary substantially across countries, as well as across regions within a country. No doubt this is a reason the GTAP model uses 18 regions of the world. However, that model treats the geographical unit as a country, not as a region. (NDSU)

Comment: There has been an accelerated rate of growth in yields for some crops due to the adoption of GM technology. Simply, the development and commercialization of genetically modified (GM) technology in corn, soybeans, canola and cotton, has resulted in an accelerated growth rate in yields. This varies by region, by GM trait, by adoption rate, as well as the now multiple-stacked traits available for these crops. (NDSU)

Comment: Given the growth in overall food and feed demand, combined with the growth in demand for biofuels, there is greater demand on agricultural resources, notably land use and technology. There are three important points regarding yields for crop production: 1) yields have had a continual growth rate

over time, with that for corn exceeding other crops; 2) there are substantial differences in yields and growth rates across regions; and 3) growth rates have accelerated in the period following introduction of GM technology. Ignoring these impacts would have a drastic impact on land use and the spatial distribution of production etc. The projected growth rates in yields are in response to new technologies developed for crop breeding and biotechnology. Further, they are the result of a cumulative accelerated growth in funding for research, the results of which will be greater yields expected over a longer period of time. (NDSU)

Comment: GTAP is a static model that does not include a time element, and is based on 2001 data which does not reflect current conditions. In essence, this means the model is stuck in 2001 and must be shocked to achieve the desired conditions. Because of this, the model is unable to account for the significant improvements in grain yields that have occurred since 2001, and are projected to continue through 2015 and beyond. (NCGA)

Comment: Due to the fact the model is unable to account for these yields improvements, the ARB staff and Purdue economists have proposed an external yield adjustment to the model. In making exogenous yield adjustments to the GTAP model predictions the ARB has amended yield from 2001 through a 2006-2008 average yield. This is highly inconsistent with the years of the ethanol shock, which range from 2001 to 2015. Assuming that historical yield advances suddenly stop is contrasted with projections from the U.S. Department of Agriculture and a number of other public and private entities, who continue to project yield increases through 2015. (NCGA)

Comment: NCGA feels strongly that the assumptions made concerning yields are incorrect. As previously mentioned there has been no accounting for increased production in future years. Because of the lack of forward vision in anticipating the contribution of further productivity, NCGA is concerned that the method upon which the external adjustments is based is logically flawed and does not go far enough in considering observed yield increases and projected improvements. (NCGA)

Comment: The Staff Report states that the diversion of agricultural land to biofuel production will exert an upward pressure on commodity prices, and potentially lead to food shortages, increasing food price volatility, and inability of the world's poorest people to purchase adequate quantities of food. This hypothesis is incorrect. It is simply negligent to omit any mention or analysis of increasing yields. (NCGA)

Comment: As a result of future yield increases and technological advances, more than enough corn will be produced to meet food, feed and fuel needs. Therefore, there are very few concerns resulting from CRP acres in the U.S. being utilized for biofuel feedstock production and producing indirect land use changes. (NCGA)

Comment: This year, US farmers will plant approximately 84 million acres to corn (nearly a 50 percent reduction), and most of that corn will be used to feed livestock. Despite the critic's unfounded claims of sod-busting and other land degradation charges, it is clear that American farmers' productivity is more than keeping pace with demand for food, feed, fuel, and fiber. (BCC2)

Comment: Advances have resulted in corn varieties with significantly greater improvements in water efficiency. Therefore, droughts will have less impact on yields than in the past. Also, areas with lower rainfall and lower soil water holding capacity will see increases in yield. These increases need to be considered by the staff. (NCGA)

Comment: The GTAP model is limited and inaccurate in several functions—mainly in the area of crop yields, and therefore cannot be used to determine and validate land use impacts. (NCGA)

Comment: It is important to note that the amount of U.S. agricultural land acreage dedicated to all crops, and coarse grains in particular, has generally declined during the last several decades while agricultural output has increased. It is also important to note that U.S. corn acreage has decreased in 2008. Historically in North America, advances in crop production technology correlate to the stabilization of forest use and a steady increase in forested acreage over the last century. Biofuel production, if carefully developed, could lead to a similar process in many third world settings, and the opposite effect of that feared. (NFA1)

Comment: Higher productivity of biofuel per acre of land utilized – The ILUC values should reflect the impact of what is likely to be higher productivity for advanced biofuels due to a combination of higher yielding dedicated crops and advanced processing techniques. (EE1)

Comment: Corn yields may increase to 289 bushels per acre by 2030 corn crop with total production of 24.6 billion bushels. With no increase in harvested corn acreage from the 2007 level of 85 million acres and growth in other uses of corn, corn available for use in ethanol production would be 12 billion bushels from the 2030 corn crop. (ILCORN)

Comment: If ethanol yield per bushel of corn remains at the current level of 2.75 gallons per bushel, total corn ethanol production in 2030 would be 33 billion gallons, compared to estimates of 7.1 billion gallons for calendar year 2007. If ethanol output per bushel of corn increases to 3.0 gallons per bushel, ethanol production would be 36 billion gallons. (ILCORN)

Comment: There are also important comments made by the peer review team selected by ARB staff. For example, one of the peer reviewers commented, "[t]hat observed data have not been used to validate the GTAP model findings is a significant weakness. The changes in corn production resulting from the federal renewable fuel standard, and the changes in Brazilian sugar production resulting from increased ethanol production should be measurable, and should be measured to validate the model assumptions ... [the ISOR] indicates that the GTAP model results cannot be validated, or have not yet been validated. Surely there is some aspect of the calculation that could be validated." One of the issues raised is one that the New Fuels Alliance and others have discussed with ARB staff for some time. The historical crop yield increases that have occurred annually over time inexplicably stop in the year 2008 through 2015. One peer reviewer notes, "[t]he lack of a time dimension in GTAP results in an awkward match with the question at hand. Corn yields have been increasing largely linearly for some time now in the United States, yet the model appears to use 2008 corn yields to determine land impacts of corn-derived ethanol. The projected steady increase in use of corn for ethanol in the US over the next few years suggests that land use change will be some what less than projected here." Assuming zero yield increases while allowing for increased biofuel production quite obviously will exaggerate the land pressures of increased biofuel production. This needs to be corrected. (NFA2)

Comment: The ARB does not include historical yield trends in its modeling. With all due respect, this is a catastrophic error that could distort the modeling results by a factor of 80 percent or more. At the most recent ARB public workshop, John Sheehan from the University of Minnesota presented data from a model he developed with the Natural Resources Defense Council which showed that once a historical yield trend is included in the analysis, the ILUC factor becomes zero because the higher productivity of agricultural land means there is more than enough crops available to address both energy and food needs. The NBB, as strongly as possible, encourages the ARB to reconsider its position on this issue. (ABCINC)

Comment: ARB should recognize the GTAP model's major weakness – that it assumes supply and demand are always in equilibrium. The ARB should address this shortcoming by adding a component to the model that can account for increasing yields, which would allow the model to show greater supply than demand over the long-term. Since substantial data exists showing supply and demand in the agriculture industry are never in balance, it is difficult to understand why the ARB would use this model for long-term forecasting. (Notably, one of the ARB's own peer reviewers made this same point in his recent response to the draft regulation by stating that GTAP should not be used for forecasting periods longer than 15 years). This limitation of the GTAP model is precisely why the ARB was unable to verify its ILUC model against 2001-2007 corn data. Of course, this is not entirely unexpected since the GTAP model was never intended for the purpose for which it is being used by the ARB. (ABCINC)

Comment: The take home message is simple—yield matters. When yields in the GTAP model are allowed to increase, whether through assumptions of increased marginal land yields or increased overall crop yields, the carbon intensity effect of land use change drops dramatically. Ironically, these results argue against CARB’s approach of looking at the global agricultural economy at a fixed point in time. Yields in global agriculture have steadily increased over the past sixty years, as is shown later in this report. (BIO)

Comment: Putting aside the arcane economic arguments over such questions as yield response to prices, these findings support the notion that future yield improvement must be considered in any analysis of future land use change impacts of biofuels. (BIO)

Comment: The CARB/GTAP and Searchinger models for land use change are, in a way, based on circular reasoning. They set up conditions such as fixed pre-biofuels land demand (in the case of GTAP) and constant yield (in the case of Searchinger), which make it almost impossible to avoid indirect land use changes. (BIO)

Comment: The biofuels “shock” implemented in GTAP is inconsistent with USDA projected crop yields. (RFA1)

Comment: We would also note that AIR, Inc. released a study, in which the findings indicated that today’s biofuels result in zero indirect land use change based on updated treatment of biorefinery co-products and yield. (OCCA)

Comment: The Staff Report evidently made adjustments in various data inputs to and outputs from the GTAP model. For example, the Staff Report acknowledges the sensitivity of results to assumptions about crop yield elasticities, land-use transformation elasticities, and trade elasticities. The Staff Report adjusted elasticity values used as inputs in the model from those the staff had previously proposed to use. Moreover, since the Staff Report used 2001 agricultural data, it had to make an ad hoc adjustment for subsequent changes in land use up to 2007. Yet, the Staff Report does not build in further experience curve effects for any of the elasticities it uses. Instead, the model freezes inputs at current levels and does not account for dynamic improvements in a wide range of land uses. Nor does the Staff Report reconcile the GTAP model inputs with extensive data on actual land use patterns experienced in the recent growth of U.S. corn production dedicated as an ethanol feedstock. Each of these modeling adjustments demonstrates the imprecision of the GTAP model, the limitations of available data inputs, and the role of simplifying assumptions. As the peer review of Mr. John Reilly concluded, discerning the effects of U.S. biofuel production on international land use patterns from available macroeconomic data is “highly confounding.” Although the GTAP model offers insights in the direction of broad economic changes caused by ethanol production, the model is not well

suited to make the precise measurements of ILUC impacts attributed to U.S. production of ethanol for use in transportation fuel. Substantial additional empirical analysis is needed to justify the parameters and data used in making GTAP calculations. Given this level of scientific uncertainty, the Board should use caution before adopting ILUC models and calculations that may be counterproductive to the Board's worthy goals. (NOVOZYM1)

Comment: An accurate and updated portrayal of modern agricultural practices and efficiencies related to inputs and production yield is lacking. According to industry experts, average yields are increasing at a faster pace than previous trend lines, and farmers have made significant improvements in fertilizer use efficiency during the past thirty years. (IOWACORN)

Comment: Direct effect GHG emissions were estimated to be equivalent to a 48 percent to 59 percent reduction compared to gasoline, a twofold to threefold greater reduction than reported in previous studies. Ethanol-to-petroleum output/input ratios ranged from 10:1 to 13:1 but could be increased to 19:1 if farmers adopted high-yield progressive crop and soil management practices. (ACE)

Comment: One potential problem with using such models is that the parameters were estimated based on historical prices, and using those parameters to project markets forward in an environment of higher prices may yield inaccurate results. In particular, the models will be prone to overstate the supply response to higher responses, and in turn overstate potential conversion of land into crop production. The key parameter in the modeling of the response of the agricultural sector is yield growth. This will ultimately have a huge influence on the amount of land needed to satisfy increasing world crop demand. With all else being equal, higher yield growth translates into lower land requirements. Any study to be used in an LCA will need to account for recent increases in yield growth for corn and yield-improving technologies that are soon to be released, which may reduce or eliminate the need for any land conversion. (ACE)

Comment: Some factors to watch in proposed LCA analysis include: Crop yield growth and input technology assumptions: Corn yield growth has accelerated over the last 10 years compared with the previous 20 years. Current yield growth may suggest little or no need for increased land area in foreign countries. Despite record ethanol use in 2007/08, corn exports were also at record levels. Technology improvements in nitrogen utilization will dramatically improve the farm GHG footprint. Ethanol yield growth assumptions: The 2007 Renewable Fuels Association survey reports average ethanol yields at 2.81 gallons per bushel, which is consistent with yields derived from the Energy Information Administration (EIA) ethanol production estimates and corn used for ethanol in dry mill plants. Future ethanol yield growth must be considered in the analysis, with 3.1 gallons per bushel a realistic yield within the next 10 years and an upside potential of 3.3 gallons per bushel. Ethanol-processing technology

continues to improve: Technology in the pipeline includes fractionation, the "no-cook process," removal of corn oil from distillers' grains, the burning of corn fiber as feedstock energy for the plant, etc. All of these technologies reduce the carbon footprint of biofuels. Almost any industry creates indirect GHG emissions and the petroleum industry is no exception. One example is the indirect GHG emissions associated with the use of the U.S. military to protect and ensure access to petroleum supplies. These indirect emissions could be estimated with more reliable data than the GHG emissions associated with indirect land use assigned to biofuels. (ACE)

Comment: We were putting over 100 million acres into corn in this country in the 1930s. The bad carbon effects come from putting nonagricultural land into agricultural production. So we've been using a hundred million acres for corn on and off. It goes up and down. Sometimes it's 80, sometimes it's 90. When we moved into corn-based ethanol, we did use more corn that was going into other things for ethanol. But corn productivity's gone up. It's about 2 percent per year. At the same time, farmers have improved their cultivation methods and we're moving more into no-till agriculture, which reduces some of the ancillary impacts of this. And, finally, then if you track through the model, you would have said by the model, "Gee, you've got all this extra corn being grown. It must be there whacking down the rain forests in Brazil to grow soy. But, in fact, rain forest deforestation in Brazil has been cut in half despite the fact that ethanol production has been increased by a factor of four or five. (GE3)

Comment: This penalty, which places ethanol fuels in the same CI category as gasoline, is derived from a general equilibrium model designed to predict the amount of land that would be converted to agricultural use if the U.S. ethanol market experienced a significant increase in demand that, under the model's assumption, would be met entirely by increased production of corn. Such a model leaves out or inadequately accounts for a whole host of economic, political, meteorological and other factors, such as technological innovation, normal declines in other crops, export declines not associated with corn or soybeans, land conversion costs of converting from nonagricultural to agricultural uses, and the discrepancies in emission estimates of stored and released carbon. These deficiencies have provoked wide-spread criticism in the scientific community. (GE3)

Comment: If ethanol yield per bushel of corn remains at the current level of 2.75 gallons per bushel, total corn ethanol production in 2030 would be 33 billion gallons, compared to estimates of 7.1 billion gallons for calendar year 2007. If ethanol output per bushel of corn increases to 3.0 gallons per bushel, ethanol production would be 36 billion gallons. (GE3)

Comment: However, we think it's premature to adopt the model and put it towards legislation until a broader scientific consensus is reached around the model especially for the indirect land use effects, which is based on assumptions

that can be challenged and does not fully take into account dynamic effects like acreage yield increases. (NOVOZYM2)

Comment: Yields should be treated as a time-dependent variable, similar to the way emissions due to indirect land use change are treated. (MONSANTO)

Comment: Objections based on Current USDA Data. The USDA Foreign Agricultural Service (USDA-FAS) maintains and updates monthly a world-region-country database of Harvested Area for the major crops of the world. This database may be accessed at <http://www.fas.usda.gov/psdonline/psdhome.aspx>. This database does not include all classes of land use, as in GTAP2001, but the conclusions about land use change of the Major Row Crops (the major feed grains, the major oilseeds, plus wheat, rice, and cotton) are striking. As shown by the table of USDA-FAS data below, the world area of the Major 10 Row Crops in crop year 01-02 was 1926 million acres, and the area of the same crops in 08-09 was 2068 million acres—an increase of 142 million acres. If such a change in row crops is reflective of changes in forest and pasture, then the actual change since 2001 is about one order of magnitude greater than indicated in the CARB staff's modeling based on static elasticities. Note from the table as well that for the United States in 01-02 the Major 10 Row Crops were 225.6 million acres, and the area of the same crops in 08-09 came to 235.6 million acres—an increase of 10 million acres. (The change would be even less if 00-01 were taken as the base year.) Such a small change in the US major row crops seems unlikely to be the driver of such a large change worldwide. How could a 10 million acre change in this country produce a 142 million acre change in the world? The answer is that the change in US acres was not a major driver of the change in world acres. The concept of "land use change" in which "land use change drives land use change" is deeply flawed. (PRX)

Comment: It is important to note that U.S. farming practices continue to advance both in sustainability and productivity. According to the United States Department of Agriculture (USDA), in 2008 American farmers produced the second largest corn crop on record and attained the second highest yield per acre in history with fewer energy and fertilizer inputs. (AFBF)

Comment: CARB has fairly and adequately accounted for yield increases. The RFA argues that CARB's baseline corn yield forecasts are too conservative and that higher yield values should be assumed. Based on the RFA comments, CARB adjusted the baseline to account for actual, observed yield increases, resulting in an 8 percent decrease in the initial iLUC estimates. In addition, no other existing fuel producers have received explicit credit for theoretical or future improvements. Future, theoretical improvements are more properly accounted for in periodic updates and Method 2B, which allows for producers to submit their individual data to receive customized pathways. CARB has committed to updating the iLUC estimate as data on yield improvements become available. In addition, ethanol producers, like all other renewable and alternative fuel

producers, have the option to submit actual data to create their own customized and unique pathway. (NRDC3)

Response: The U.S. ethanol output in 2001 was about 1.5 billion gallons and the reported U.S. ethanol output for 2008 was about 8.5-9.0 billion gallons. The Staff Report page IV-29 states: “Because the modeling runs used a baseline year of 2001, the model output corresponds to a new equilibrium achieved in 2001 after introducing a 13.25 billion gallon increase in corn ethanol production. These results must be corrected for the changes in agriculture that have occurred between 2001 and present. The change that most significantly affects model output is an increase in crop yields. In 2001, the average corn yield in the U.S. was 138.2 bushels per acre and the average corn yield for 2006 to 2008 was 151.3 bushels per acre which represents a 9.5 percent increase over 2001. We used a three year average because yields can fluctuate significantly on a year to year basis. An adjustment for this yield increase was applied to the model results. The model itself was not modified and re-run.”

Also page IV-31 of the Staff Report presents the adjustments for sugarcane ethanol as follows: “Like the corn ethanol results presented above, the sugarcane ethanol land use change results presented in this section were produced using GTAP with a 2001 baseline. The results simulate the GHG-generation impacts of an increase in Brazilian sugarcane ethanol production from 3.61 billion gallons to 5.61 billion gallons. Model outputs were updated to reflect the 8.2 percent increase in Brazilian sugarcane yields observed between 2001 and the average for the 2006-2008 time period.”¹⁸

The external adjustment performed on the GTAP model for indirect land use effects captured the increases in yields for crops that happened up to 2008, i.e., current technology. Future increases were not included because it is not possible to forecast which new technology will be adopted in the market place in years to come. Not including the yet unproven technologies to adjust yield increases has made the indirect land use impact portion consistent with the GREET modeling portion that estimates the direct effects of land use impacts. In the GREET modeling, the projected carbon intensity values were given for the current technology as of 2008. With that in mind, staff recommended and the Board approved the method of combining the two direct and indirect effects from the current 2008 data.

The model input that endogenously determines the extent to which crop yields change in response to the prices farmers receive for their crops is the “crop yield elasticity.” As prices rise, farmers will increase their investment in the more lucrative crops: they will increase fertilizer and pesticide applications; they will irrigate and cultivate more frequently; they will increase the number of plantings per rotation cycle and reduce or eliminate fallow periods; and they will implement any other measures that are known to increase yields. These are the measures farmers are known to take in order to improve their returns in response to higher crop prices. Short-run price fluctuations do not

¹⁸ Ministério Da Agricultura, Pecuária E Bastecimento, Secretaria De Produção E Groenergia, Departamento da Cana-de-Açúcar e Agroenergia. “Brazilian Sugarcane Productivity Evolution.” (Ca. 2008)

stimulate investments in long-term improvements such as the development of new varieties, however. Long-term innovations are considered “exogenous” to the model: they are not influenced by the relatively short-term price changes being modeled. As the time period covered by the model increases, however, underlying exogenous changes can affect baseline yields (short-term, price-driven yield changes fluctuate around the long-term baseline yield). This was found to have occurred in the case of the corn ethanol production increases being modeled. In response, the modelers increased baseline yields, as described on page IV-29 of the ISOR.

Some commenters state that other secondary indirect impacts of higher prices in crop intensification were not accounted for either. Such effects occur when the increase in price of crops, like corn, likely reduces purchase of feed by the livestock industry. This in turn, reduces livestock production and increases the price of cattle and meat to the consumer. Actually, such effects are taken into account in the model endogenously by the trade elasticities existing in the model. (There is a substitution from corn to other feedstuffs, but the combined effect is reduced livestock production.) Reduced livestock production entails reduced enteric fermentation. However, ARB did not include emissions adjustments for reduced enteric fermentation in livestock, but will continue to analyze relevant scientific studies and make appropriate adjustments in the future if deemed necessary.

In regards to all the indirect land use effects, the Board has directed the Executive Officer to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analyses of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. There will be additional opportunities in the future to visit the main issues on land use change. The Board has included in the Resolution 09-31 a mechanism for formal review of the LCFS program to be conducted in years 2011 and 2014.

Intensification and Inputs Efficiencies of Biofuel Crops

L-41. Comment: The last issue that I request be reviewed is the adoption of land use change (LUC) into the LCFS. The usage of a model that is not peer reviewed for LUC modeling, uses data that does not reflect the increase in efficiencies to shock the model and is not widely adopted or supported amongst the scientific community I don't believe it should be used to develop or adopt regulations. (NCB)

Comment: Another issue that we feel needs to be reviewed is the adoption of land use change (LUC) into the LCFS. The model that CARB is looking to use is not peer reviewed, uses data that does not reflect the increase in efficiencies and is not widely adopted or supported amongst the scientific community. We do not believe this model should be used to develop or adopt regulations. Before adopting LUC a study on these changes should be required, thus allowing any

model to be peer reviewed and any data from a model to be validated for soundness. (MCGA)

Comment: It also discusses how technology innovations are making both corn and ethanol production more efficient and carbon-friendly, developments that have clearly not been captured not quantified adequately by CARB in its analysis and modeling for the proposed LCFS. (ACE)

Comment: This penalty, which places ethanol fuels in the same CI category as gasoline, is derived from a general equilibrium model designed to predict the amount of land that would be converted to agricultural use if the U.S. ethanol market experienced a significant increase in demand that, under the model's assumption, would be met entirely by increased production of corn. Such a model leaves out or inadequately accounts for a whole host of economic, political, meteorological and other factors, such as technological innovation, normal declines in other crops, export declines not associated with corn or soybeans, land conversion costs of converting from nonagricultural to agricultural uses, and the discrepancies in emission estimates of stored and released carbon. These deficiencies have provoked wide-spread criticism in the scientific community. (GE3)

Comment: For example, ARB's onroad emissions model (EMFAC) has been validated by real world carbon monoxide data based on ambient air monitors in tunnels. Conversely, there has been little attempt to validate the inputs or outputs used for the GTAP analysis. There are indications that some of their assumptions may be wrong. For example, GTAP assumes that the productivity of new land being converted is 40% less than existing land. However, this assumption does not square with actual yield and productivity data coming out of Brazil. (MDV1)

Comment: However, another factor that was not properly and completely considered is farming intensity. This is a name for what happens when farming intensity increases and more food is grown on less land. Dr. O'Hare and Mr. Fletcher mentioned the direct effect of farming intensity that results from increased ethanol demand. It seems clear that this increase in farming intensity will be achieved primarily with increases in water and fertilizer use. And I want to point out that this intensification of farming occurs on the entire world's farming system. And so even a small increase in the greenhouse gas intensity on the entire world' farming will be significant. (TESORO2)

Comment: WSPA requests that ARB evaluate potential net changes in GHG emissions from world-wide food production due to the phenomenon of intensification. If so, this incremental GHG impact should be assigned to the incremental ethanol production that would be the reason for these changes. (WSPA1)

Comment: To correctly account for all of the indirect effects resulting from an increase in ethanol production, ARB should factor in all of the resulting impacts, not just the change in land crop production. We question why ARB has not accounted for the effect of world wide intensification in their analysis. We point out the UC analysts called on ARB to include the effects of intensification. (WSPA1)

Comment: WSPA requests more details on the LUC numbers. How many acres of what type of land were converted for CBE (acres/100 gallons ethanol)? What are the effects of intensification on the efficiency of corn production and N₂O conversion? Can ARB show these details in their backup document? (WSPA1)

Response: The crop yield elasticity used in the model addresses the intensification and inputs efficiencies of crops. An increase in the price of a crop results in increase in the yield response for that crop which consequently reduces the net land use effect in the model. It should be noted that the additional inputs such as chemical fertilizers, increase the carbon intensity of the crops produced from these lands. (For more discussions of this issue please refer to the Yield Adjustment Section, above.)

Crop Rotations and Biofuel Crops

L-42. Comment: Are there carbon costs allocated to biofuel crops as a result of crop rotations? How are you distinguishing between a rotation and a new land use? (LEONARD)

Response: Increasing worldwide demand for biofuels will stimulate a corresponding increase in the price and demand for the crops used to produce those fuels. Some of the methods used to increase the biofuel crop production are to grow more biofuel feedstock crops on existing crop land by reducing or eliminating crop rotations, fallow periods, and other practices which improve soil conditions but reduce the number of harvests over time. ARB modelers were aware that if price of a biofuel crop such as corn is raised relative to prices of other crops, such as soybeans, farmers will plant more of corn and less of soybeans, altering the traditional annual rotation of the two crops. To capture the yield changes occurring between the two crops, modelers use crop yield price elasticity based on empirically derived values. Thus, tradeoffs between crops are endogenously estimated in the model. However, ARB did not assign a discrete carbon intensity emissions value to the change in rotation patterns, or any other measure taken by farmers to increase yields of higher-valued crops. The crop yield price elasticity expresses the combined effects of all such measures.

Individual Yields and Plant Efficiencies

L-43. Comment: Yield increases in the surrounding plant draw area were sufficient to meet the IRE corn demand. (IRELLC)

Comment: An advanced closed-loop biorefinery with anaerobic digestion reduced GHG emissions by 67 percent and increased the net energy ratio to 2.2, from 1.5 to 1.8 for the most common systems. Such improved technologies have the potential to move corn-ethanol closer to the hypothetical performance of cellulosic biofuels. Likewise, the larger GHG reductions estimated in this study allow a greater buffer for inclusion of indirect-effect land-use change emissions while still meeting regulatory GHG reduction targets. These results suggest that corn-ethanol systems have substantially greater potential to mitigate GHG emissions and reduce dependence on imported petroleum for transportation fuels than reported previously. (ACE)

Response: The Board recognized this and encourages fuel producers, subject to certain criteria to create improved or new fuel pathways using Methods 2A and 2B, as stated in the Board Resolution 09-31. This will allow producers to take advantage of advances in technologies such as described in the comment.

National vs. Regional Crop Yields

L-44. Comment: On page IV-29, under “Adjustment of GTAP Model Results,” the CARB staff proposes that the main adjustment required in adapting GTAP to the present year (2008) is simply to adjust the corn yield. Two smaller questions arise:

(a) Why is the US aggregate average corn yield of 138.2 bushel per acre in 2001 used instead of the mid-western cornbelt average (12 main cornbelt states) of 139.9? And

(b) Why are the three recent years of 2006, 2007, and 2008 averaged in the proposal looking ahead to 2011-2020, as opposed to extending the corn yield trend, even the well-established trend of 1973-2004?

For the three years 2006-2008, the cornbelt average yield would be 154.8 bushels per acre, instead of the US aggregate 151.3 cited by CARB staff. The average of the 1973-2004 yield trend for the cornbelt states during the period 2011-2020 would be 167.5. The CARB staff should consider a dynamic approach to forward regulations, not a static approach. (PRX)

Response: The ARB uses aggregate average corn yield to reflect a nationwide average yield. Ethanol will be produced from corn originating from all parts of the country and not just the Midwest. The ARB is using current average yields in order to reflect current real-world conditions. Future projections can often vary greatly and end up being inaccurate. During the implementation of the regulation, the staff will monitor real-world corn yields and make any needed changes to the regulation to reflect changes in corn yields.

Sensitivity to Uncertain Elasticity Values

GTAP Model Inputs

L-45. Comment: The treatment of indirect GHG emissions is questionable.

There are uncertainties in the elasticities and other values and coefficients used in CGE models (including the GTAP) result in unreliable estimates that, in some cases, have been shown to have imprecisely predicted actual known outcomes. GTAP model is not complex enough to accurately determine how various biofuel feedstocks will affect land use decisions worldwide and, therefore, should not be the basis for a regulatory action. Furthermore, these models are especially sensitive to the assumptions underlying the inputs and processes included in the model. Elasticities presented are inaccurate and have no rational or scientific basis. In particular, assumptions regarding the supply of agricultural land, the availability of marginal lands, farmer behavior, agricultural production practices, economic value and use of biofuel co-products, and competing uses for land and natural resources, substantially affect model results. Determining the 'right' assumptions and assigning values can be a highly subjective process over which scientists, policymakers, and stakeholders frequently disagree. (AIRE, SUDERMAN, NDSU, UNE2, ACE, UNICA, CALSTART, 111SCIENTISTS, NFA1, UIC1, NCSU, BS, ILCORN, NFA3, NFA2, COMF1, RFA1, KLINE, ABCINC, BIO, NOVOZYM1, TNSP, CONOCO, EESI1, PRX, COMF3, COMF2, VERENIUM, SHELL, MONSANTO, NCSU, RFA1)

Response: The approved LCFS regulation was developed using the best available economic and scientific information. The Board acknowledged in Resolution 09-31 that the available methods for estimating indirect impacts (including land use change) are relatively new and the indirect values for crop-based biofuels included in the regulation approved may be different from values that may be generated in the future based on more robust data and more advanced analytical tools. Although some commenters argue that there are uncertainties and GTAP is not complex enough, the GTAP model contains components that are necessary for evaluating the effects of land use change impact for biofuels. In addition, GTAP is transparent and publicly available. Some other commenters state that such models are sensitive to assumptions, and determining the 'right' assumptions and assigning values can be a highly subjective process. These issues have been addressed by evaluating different parameter and elasticity values. The assumptions used for parameter values were based on information collected by Purdue's GTAP center and it represents the best data available. The Board also acknowledged the public participation in the regulatory process as staff conducted sixteen public workshops regarding the proposed LCFS in 2008 and 2009 and also participated in numerous other meetings with various stakeholders and other outreach efforts in order to include the public and affected stakeholders in the regulatory development process. The issue of elasticities and other GTAP parameters were discussed during the public workshops and meetings, and as the result of the public inputs, adjustments were made to the model for corn and sugarcane ethanol. The ISOR for LCFS prepared by staff is where the rationale for the land use change estimates is explained. The ISOR was produced for public comment 45 days prior to the public hearing of the proposed regulation. The scientific portion and the ISOR of the proposed regulation were reviewed by four peer reviewers prior to the public hearing. None of the reviewers required a major modification to either the proposed regulation or

the analysis used to support the proposal. In the Resolution 09-31, the Board also directed staff to convene an Expert Workgroup to thoroughly evaluate the estimation approach it has taken, as well as the available alternatives for land use change impacts. It further directs staff to report the results of the Expert Workgroup findings to the Board by December 2010. The Board has also directed staff to perform a comprehensive evaluation of the LCFS program in 2011 and 2014.

Some commenters have criticized CARB for the use of specific parameters and input elasticity values arguing that other values are more appropriate. Others are requesting that CARB simultaneously change multiple elasticity values in a similar direction. All acknowledge that there are uncertainty ranges around the GTAP elasticities. Some commenters recommend selecting elasticities from these ranges in such a way as to produce desirable carbon intensity values. On the other hand, staff presented and the Board approved selected mid-points from the full range of reasonable elasticity values. This approach avoided the bias associated with methods which select values that are closer to the range boundaries than to the midpoints. In other words, GTAP parameter distributions are from literature, once GTAP is run and solved, confidence intervals are constructed and an appropriate central value is selected for land use change impact. For example, to select an appropriate central value for the land use change impact of corn ethanol production, we narrowed down the range of values from the sensitivity analysis by removing the results obtained from the most improbable combinations of input elasticity values. These variables, and the narrowed, 'most reasonable' ranges, were used. It is possible that range around the current central value estimates is wide, but it does not contain the value "zero" for indirect land use change. The changes requested by most of the commenters would produce new estimates that are well within the bound range surrounding the current Board-approved land use change impact estimates. Moving these estimates around within the current bound range is neither meaningful nor helpful. Changing multiple elasticity values simultaneously in a similar direction will also skew the results of ILUC. CARB plans to reassess the elasticity issues and the modeling work through the Expert Workgroup. Once the Expert Workgroup is able to guide CARB to estimates with a narrower uncertainty range, such changes become meaningful and worthy of consideration. The Board has also directed staff to perform a comprehensive evaluation of the LCFS program in 2011 and 2014.

Ethanol Shock

L-46. Comment: The basis for the choice of the size of the sugarcane ethanol shock (2 billion gallons) was not explained in the Staff Report or during public hearings. It is uncommon to find in the literature on the computational general equilibrium (CGE) model demand shocks, as implemented by CARB. It was surprising to that CARB chose such large demand shocks. With a slightly smaller shock (increase ethanol demand from Brazil in 1.5 billion of gallons), smaller land use changes and smaller ILUC carbon intensity numbers were observed. (UNICA)

Response: The choice of the size of sugarcane ethanol shock is based on an expected demand for sugarcane ethanol in the U.S. of 2 billion gallons. However, in

performing the analysis and it was found that model results proved insensitive to the size of the sugarcane ethanol “shock” (a similar insensitive of results to shock size was found with corn ethanol). The carbon intensity values in gCO₂/MJ based on GTAP data were linear with the size of the production increases in the fuel. The increase of 2 billion gallons was discussed in public workshops and was considered appropriate for the analysis in the sugarcane ethanol model. In recognition of this, the Board has directed the Executive Officer to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified.

Model Assumptions and Inputs, Science Imprecise

L-47. Comment: Using an economic model to predict worldwide carbon effects, and the outcomes are unusually sensitive to the assumptions made by the researchers conducting the model runs. The accuracy of the model data assumptions, methodology, and other key factors underlying the GTAP runs made by CARB is questionable. CARB is using ideology while ignoring good science to drive policy, with concerns about the volume of old and misleading data being used to shape public opinion on the land use charge for biofuels. Simply, the assumptions do not reflect the current and evolving technology in these industries. The fact that these models are peer-reviewed should not be inferred to mean that they have been peer-reviewed to be used for the purpose of enforcing indirect effects against specific fuels in a carbon-based fuel regulation and using them is poor public policy. None of the peer reviews finds that the GTAP model (including its assumptions of causal relationships and its parameter values) is robust, that the assumptions and parameters underlying the model have been validated by real world data. (111SCIENTISTS, UNICA, CALSTART, UNICA, BS, TNSP, NFA1, SHELL, EES1, SUDERMAN, NDSU, ABFA, WINNISON2, ACE, BIO)

Comment: As such, these models also often represent an agglomeration of parameters cobbled together from a variety of different sector-specific analyses. In fact an ex-post evaluation of the predictive power of these models reveals very weak empirical performance. Kehoe (2002) considered the performance of CGE models in projections of the economic effects of NAFTA. He concluded that “they did not do a good job” and points out that the correlation of the predictions of such models with what actually happened was very low in many cases. Such models have also been criticized for their weak econometric foundations (see, for example, McKittrick (1998) and Jorgenson (1984)). The GTAP developers outline and discuss these very criticisms (Hertel et al., 2003). They note that the models are based upon price and substitution elasticities gathered from a variety of (mostly sector-specific, partial-equilibrium) time-series studies. These individual estimates do not represent precise statements of truth but rather are estimates subject to varying degrees of estimation error (e.g., standard errors of the estimates). (NCSU)

Comment: Without a doubt an indirect land use penalty of 46 gCO₂/MJ for sugarcane ethanol has no scientific basis. As shown by our analysis, there may well be carbon credits generated in sugarcane production if the model is reasonably calibrated. (UNICA)

Comment: Our analysis based on all of CARB's assumptions is that the corn ethanol land use number should be about 28 instead of 30. (AIRE)

Comment: A commenter asserts that GTAP modeling runs with reasonable adjustments to certain assumptions performed by Air Improvement Resource, Inc. resulted in corn ethanol ILUC emissions in the range of 8 g CO₂-eq./MJ, significantly lower than CARB's estimate of 30 g CO₂-eq./MJ. Thus, CARB should refine the ILUC analysis assuming a more balanced and less pessimistic set of assumptions. (RFA1)

Comment: We are currently expanding our bottom-up modeling approach to include more ethanol plants. We urge CARB to provide a mechanism to allow individual ethanol producers to demonstrate their plant's impact on land use change. (UIC1)

Comment: The staff of CARB needs to work closely with experts in the field with first hand information to gather accurate information for the development of their model. (ILCORN)

Comment: Novozymes does not contend that ILUC impacts of ethanol pathways are necessarily zero. Rather, the immaturity of ILUC modeling and the questionable basis for assumptions used in connection with the GTAP model (both as to its input parameters and the use of its outputs) provide insufficiently rigorous scientific support for the specific ILUC penalties and carbon intensity values proposed in the Staff Report and Lookup Tables for each ethanol pathway. (NOVOZYM)

Comment: In sum, the market-mediated land-use change impacts hypothesized by GTAP and similar economic models are not merely inaccurate estimates; they may indeed be the opposite to what could be expected in the real world, particularly when one looks at first time forest conversion and biofuel production backed by incentives for sustainable production, environmental legislation and enforcement. More research is needed to better understand the interactions among these factors, going beyond theories, to calibrate and validate models that reflect how behavior is impacted, and to better quantify the degree and direction of impacts from biofuels. (KLINE)

Comment: Finally, the establishment of preliminary indirect land use carbon emission impact estimates on the use of vegetable oils (particularly soy oil) to make biodiesel undermines the use of conventional biodiesel. The current staff

report adopts a number of preliminary assumptions with respect to the indirect land use impacts of vegetable oils used as a biodiesel feedstock that reduce the attractiveness of biodiesel as a means to reduce carbon intensity. The lack of specificity and clarity related to the ILUC for vegetable oil biodiesel also has implications for capital investment decisions that will be necessary to build additional biodiesel capacity. (COMF1, COMF2, COMF3)

Response: The GTAP is designed to project the specific effects of one carefully defined policy change—namely the increased production of a biofuel. Because it focuses narrowly on a specific set of economic changes, the results obtained from GTAP will not necessarily reflect observed aggregate trends. As stated in the Board Resolution 09-31, the scientific portion of the regulation and the Staff Report were reviewed by four peer reviewers. The Board considered the four peer reviews prepared pursuant to section 57004 of the Health and Safety Code; none of the reviews required major modifications to either the proposed regulation or the analysis used to support the proposal. The Board agrees—for the reasons cited in these comments—estimating the indirect land use impacts of fuel production from ‘actual’ land conversion data is currently difficult. For example, the RFA1 commenter asserts that Air Improvement Resources Inc.’s model resulted in corn ethanol ILUC emission in the range of 8 g CO₂/MJ versus the 28 g CO₂/MJ as estimated by CARB’s GTAP modeling. Also, the Air Improvement commenter stated that “Our analysis based on all of CARB’s assumptions is that the corn ethanol land use number should be about 28 instead of 30.” The Air Improvement Resources adjustments to the model unlike CARB’s were never shared with the public or the GTAP modelers. All acknowledge that there are uncertainty ranges around the GTAP elasticities. Some commenters recommend selecting elasticities from these ranges in such a way as to produce desirable carbon intensity values. We, on the other hand, selected mid-points from the full range of reasonable elasticity values. This approach avoided the bias associated with methods which select values that are closer to the range boundaries than to the midpoints. CARB chose the best available model, the GTAP, to evaluate land use change impacts with public input. (For further discussion on public participation see the response to Comment L-1). The increase in land use change due to biofuels production is relatively small compared to land use change for other real world events such as population expansion, changes to higher protein diets, and catastrophic events such as floods, fires, and earthquakes. That is why it is necessary to estimate these impacts using a model that faithfully captures and quantifies the overriding economic forces that drive land use change. (For further discussion on assumptions, see the response to Comment L-1). The LCFS GTAP model contains tight theoretical specifications and unlike other types of economic models, it can provide insights into changes for which there is no historical experience. The GTAP model however, produces predictions that are consistent with well-understood and often-observed historical behaviors. To assert that the GTAP simply imputes the biases of modelers and regulators is to ignore the strong historical and empirical basis of the relationships captured in the model. In this regard, the Board has directed the Executive Officer to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with

regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. As for a mechanism to allow individual ethanol producers to demonstrate their plant's impact on land use change, the Board allows individual producers to create their own pathway using Method 2A, if they can demonstrate a 5 gCO₂e/MJ improvement, as stated in the Resolution 09-31. And lastly, the values reported in the Staff Report for soy biodiesel were preliminary. Another set of land use change values for oilseed crops will be released for comment.

Dynamic Changes

L-48. Comment: The Staff Report used 2001 agricultural data. It had to make an ad hoc adjustment for subsequent changes in land use up to 2007. The model freezes inputs at current levels and does not account for dynamic improvements in a wide range of land uses. Nor does the Staff Report reconcile the GTAP model inputs with extensive data on actual land use patterns experienced in the recent growth of U.S. corn production dedicated as an ethanol feedstock. (NOVOZYM)

Comment: CARB staff does not demonstrate that GTAP elasticities derived from land use changes due to annual and smaller market changes might not be completely misleading with respect to the elasticities induced by large, long-term policy changes. (PRX)

Comment: The analysis of such impacts must recognize the dynamic effects of changing commodity prices on the level of crop consumption and the implications for total U.S. and world crop production that is needed. The analysis must also be able to separate the crop land impact of the increased use of corn based ethanol in the U.S. from changes in other variables such as world economic conditions and trade policy. (UIUC1)

Response: It would be impossible to isolate and correlate the land use change effects of increased biofuels production to actual land use patterns in the U.S. The increase in land use change due to biofuels production is relatively small compared to land use change for other real world events such as population expansion, changes to higher protein diets, and catastrophic events such as floods, fires, and earthquakes. GTAP is calibrated to account for fluctuations in the parameters mentioned in the comments. The model itself is based on 2001 world data, because it was the best available and most aggregated dataset. The Staff Report on page IV-29 states: "Because the modeling runs used a baseline year of 2001, the model output corresponds to a new equilibrium achieved in 2001 after introducing a 13.25 billion gallon increase in corn ethanol production. These results must be corrected for the changes in agriculture that have occurred between 2001 and present. The change that most significantly affects model output is an increase in crop yields. In 2001, the average corn yield in the U.S. was 138.2 bushels per acre and the average corn yield for 2006 to 2008 was 151.3 bushels per acre which represents a 9.5 percent increase over 2001. We used a three year average because yields can fluctuate significantly on a year to year basis. An

adjustment for this yield increase was applied to the model results.” Furthermore, the elasticity values that modelers used were based on literature information. The Board has directed the Executive Officer to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. The Board has also directed staff to perform a comprehensive evaluation of the LCFS program in 2011 and 2014, where—if appropriate—further adjustments to yields can be made.

Elasticity of Crop Yield with Respect to Area Expansion

L-49. Comment: Yields on "new" crop land are significantly underestimated and the elasticity of crop yields with respect to area expansion should be raised to at least 0.75. The European Union has operated a mandatory "set-aside" program which requires farmers to keep 10 percent of their land out of food production. Farmers are allowed to choose which land to keep out of production, resulting in less productive land selectively being removed from production. A European Commission funded study on the set-aside found that yields on fields farmers included in the set-aside varied from 50-95 percent of farm average yields, with an average yield on the set-aside land of 70-75 percent when compared to farm average yields. This represents the yield potential of the bottom 10 percent of agricultural land in the countries affected by the set-aside program. Unlike the U.S. and European Union, there is still considerable land that is "well-suited to crop production" that has not yet been brought into production in South America, particularly in Brazil. Soybean yields in Brazil and Argentina at least match those seen in the United States (USDA 2008). At the same time soybean production area has doubled over the past decade. If this new land were as unproductive as CARB's 50 percent productivity number suggests, yield parity with the US would be impossible. Rather, the high yields observed in these countries would justify setting the elasticity of crop yield with respect to area of expansion at 1.0. In addition to high soy yields, double cropping is common in the Central region of Brazil, with some 12 million acres typically planted in corn following the harvest of the soy crop. Yields on the second crop (called safrinha crop) are lower than full season crops, but represent an important source of grain that may not be captured in the CARB model. With soy yields equal to the US and the addition of a second corn crop, a newly converted acre in Brazil will be higher in overall productivity than an acre of soy in the US. Key references:
<http://www.pecad.fas.usda.gov/highlights/2008/04/Brazil/>
http://www.conab.gov.br/conabweb/download/safra/boletim_ingles_completo.pdf
Along with farming practices, yields vary considerably by region from the relatively high yields of South Africa to the low yields of Tanzania and Zimbabwe. Land conversion is also likely to vary considerably by region, with high productive new land being brought into production in some areas, but fallow periods being reduced or already destructive farming practices increasing in other regions. This suggests that a higher resolution estimation of land use change in Africa is

needed to estimate an elasticity of crop yield with respect to area of expansion. (MONSANTO).

Comment: Empirical data in Brazil shows that the crop yield elasticity with respect to area expansion should be around 0.9 to 0.95, rather than in the range of 0.5 to 0.75. Therefore, CARB should run all scenarios for Brazilian sugarcane ethanol using 0.90 crop yield elasticity with respect to area expansion, in order to avoid overestimations of land conversion for Brazil. CARB should adjust the sugarcane land use change to reflect the total gains in yield, which is 16.6 percent, rather than 8.2 percent. (UNICA)

Comment: The fact that almost all of the land well suited to crop production has already been converted can be true in the United States and the European Union. But, in many other parts of the world, as in Latin America, and particularly Brazil, there is considerable, potentially well-suited agricultural area for crop expansion. Some studies have shown this potential in terms of land available to agriculture or biomass production, as Chou et al. (1977), Edmonds and Reilly (1985) and Bot et al. (2000) show us. Such research suggests that the elasticity of crop yields with respect to area expansion is potentially larger in those regions with larger land availability. (UNICA)

Comment: For the improved yield elasticity with respect to area expansion, we use a value of 0.7 to 0.9, in place of CARB's assumption of 0.5 to 0.7. The value is probably closer to 1.0 (or higher than 1.0, as demonstrated by the Brazil soybean case outlined in Appendix C), but we are using 0.7 to 0.9 to account for a few areas where it may be slightly less than 0.9. This change is made to the GTAP model inputs. We retain all of CARB's other GTAP elasticities. The updated area expansion elasticities are shown in Table 8. (RFA1)

Comment: Elasticity of crop yields with respect to area expansion: In most parts of the world, a majority of the land that is well-suited to crop production has already been converted to agricultural uses. Therefore, yields on newly converted lands are almost always lower than corresponding yields on existing crop lands. This parameter is equal to the ratio of yields that will be realized from newly converted lands (marginal yields) relative to average yields on acreage previously devoted to that crop. In economic terms, it is the ratio of marginal to average yields within an agro-ecological zone. Although this is a critical input parameter, little empirical evidence exists to guide the modelers in selecting the most appropriate value. Based on the professional judgment of those with experience in this area, the modelers selected a value of 0.66. For purposes of the sensitivity analysis this parameter was varied from 0.25 to 0.75. This input variable produced by far the greatest variation in the output GHG variable: 77 percent. (SHELL)

Comment: The elasticities of crop yields with respect to certain factors as discussed in Appendix C5 are questionable. This is particularly true for the

elasticity of crop yields with respect to area expansion. As stated on page C-29, “Although this is a critical input parameter, little empirical evidence exists to guide the modelers in selecting the most appropriate value.” This is unfortunate since, depending on the parameters used, there was a “77% variation in the GHG emission estimate.” (RFA1)

Comment: Additionally, “professional judgment” was used to set the parameter; however, the amount of error that could be introduced by this variable suggests that the elasticity should be determined empirically or it should be excluded from the model. The parameter was judgmentally set at a value of 0.5, indicating that yields on new land are far less than those on land previously planted to the crop. A brief examination of the data indicates that the empirical evidence for such a low value is lacking. (RFA1)

Comment: The best example of this can be seen by examining the area and yields of soybeans. As shown in Table 2, soybean area outside the U.S. almost exactly doubled between the 1989-1991 period and the 2006-2008 period, from 33 million hectares to 65 million hectares. (Much of the increase occurred in South America.) During the same timeframe, yields increased by 38%. This was significantly higher than the 23% yield increase that occurred in the U.S. on a 23% increase in soybean area. If new land were far less productive than previously planted land, the large increase in non-U.S. yields would have been logically suspect, and at a minimum the increase would have been expected to have been lower than that of the U.S., where the percentage area increase was only one-fourth as large. (RFA1)

Comment: The results for corn are not as dramatic as those for soybeans, since the expansion in area has not been as large in percentage terms, but area and yield patterns for corn point in the same direction as those for soybeans. Both U.S. and non-U.S. corn area grew by roughly one-fifth between the 1989-1991 period and the 2006-2008 period. Over that timeframe, yields increased by approximately one-third. Additionally, the increases outside the U.S. have been slightly higher than those for the U.S.: non-U.S. yields increased 34% on an area increase of 22%, while U.S. yields rose by 32% on an area expansion of 18%. (RFA1)

Comment: In Appendix C-5, the first comment about the elasticity of crop yields with respect to area expansion is, “Because almost all of the land that is well-suited to crop production has already been converted to agricultural uses, yields on newly converted lands are almost always lower than corresponding yields on existing crop lands.” (C-29) One of the main areas of the world where a substantial amount of new land has been brought into crop production during the last couple of decades is Brazil. From 1989 to 1998, major crop area in Brazil increased by 9 million hectares, virtually all accounted for by an increase in soybean area. A review of Brazilian soybean yields by state produces results that are contrary to the assertion that “yields on newly converted lands are

almost always lower than corresponding yields on existing crop lands.” In fact, as shown in Figure 1, the Brazilian states where soybean area expansion has been the greatest over the last two decades have tended to have higher yields than those where less expansion has taken place. In recent years, yields have been highest in Mato Grosso, where soybean area expanded by 3.8 million hectares between 1989 and 2008, an increase of 223%. The second-highest yield in 2008 among states reflected in Figure 1 (the top five states by soybean area) was in Goias, where soybean area has increased by 1.2 million hectares since 1989, or 120%. Both states experienced yields that were higher than the Brazilian average, and yields in Mato Grosso have been consistently above the national average. Parana is a more traditional soybean-producing state, and its yields have been consistently above the national average. However, there has been considerable expansion in Parana as well, with 1.6 million hectares more planted in 2008 than 1989, an increase of 68%. Back in 1989, Rio Grande do Sul was the largest soybean-producing state in Brazil, accounting for 30% of the country’s planted area. However, there has been little soybean area expansion in the state, and yields significantly lag the national average and are more variable than in the other major states. In summary, yields in the “new” soybean states of Mato Grosso, Mato Grosso do Sul and Goias were 31 quintals per hectare (3.1 metric tons per hectare) in 2008, compared to an average 25 quintals per hectare in the more established soybean growing states of Parana and Rio Grande do Sul. Averaged over the last three years (2006-2008), the yield differential was slightly smaller, with the “new” states averaging 29 quintals per hectare and the established states averaging 25 quintals per hectare. (RFA1)

Comment: Looked at another way, the combination of substantial soybean area growth and increasing yields in Brazil and Argentina demonstrate that it is mathematically unlikely that the assignment (based on judgment) of a value of 0.5 to the elasticity of crop yields with respect to area expansion is correct. Given actual national average soybean yields that have occurred in the U.S., Brazil and Argentina since 1994, Figure 2 shows soybean yields that would have had to be achieved on the land on which soybeans were grown in 1994, if the yield elasticity for new land were 0.5. By 2007, the yield on existing land would need to have been 42 quintals per hectare (62 bushels per acre) in Argentina and 37 quintals per hectare (55 bu/ac) in Brazil, which is far higher than the 29 quintal-per-hectare (43 bu/ac) yield implied for existing land in the U.S. It is also roughly double the 22 quintal-per-hectare (33 bu/ac) yield that occurred on the same land in Brazil in Argentina in 1994. Actual national average yields in 2007 were roughly 28 quintals per hectare (42 bu/ac) in all three countries in 2007 (across all area planted). (RFA1)

Comment: In conclusion, regarding the elasticity of crop yields with respect to area expansion, given the findings provided above, it cannot be determined that yields on new area have been meaningfully different than yields on area previously planted to crops (i.e., that the elasticity is less than 1). It appears that “judgment” was used to set the value for the elasticity parameter at an

unrealistically low level; ARB should correct this by obtaining empirical data regarding actual yields on existing crop land versus newly planted land (RFA1)

Comment: We would be interested in seeing any data the ARB has that shows clearing land for additional plantings is less expensive than improving agricultural practices such as purchasing higher quality seed varieties. Based on our calculations, the math does not come close to supporting this assumption, meaning the ARB believes farmer-business people will consistently – and on a long-term, worldwide basis – make decisions counter to their economic best interest. Page X-4 of the proposed regulation states that “The lowest cost way for many farmers to take advantage of these higher commodity prices is to bring non-agricultural lands into production.” This assumption causes the ILUC model to predict that a significant amount of new land will be brought into agricultural production, artificially increasing the ILUC factor and thus decreasing biodiesel’s GHG benefits. (ABCINC)

Comment: CARB has considered and incorporated a higher range of values for crop yields on converted lands. RFA argues that CARB underestimates the productivity of converted lands. CARB observes that new acreage almost always has lower yields than lands already in use, simply because the best lands for crops have already been utilized. CARB’s approach has been to consider a range of sensitivities reflecting estimates that marginal land is 25 to 75 percent as productive as land currently used for agriculture, with 50 percent being the best professional judgment of experts. However, based on feedback from RFA, ARB Staff and GTAP modelers have updated the range used to 50 to 75 percent. CARB has also committed to continued analysis of the available data and evidence, and to update its results as appropriate. CARB’s changes have resulted in an additional decrease of 6 percent from the initial iLUC estimate. (NRDC3)

Response: The elasticity of crop yield with respect to area expansion was modeled to capture the yields that will be realized from newly converted lands relative to yields on acreage previously devoted to that crop. The set-aside programs in the European Union were created to combat the depressed commodity prices of the late 1980s and the 1990s. It is very conceivable that the farmland set-aside in Europe may have to had better than the world’s average in productivity. But that does not mean that the elasticity values for marginal lands in all areas should be taken as high as those in Europe. One commenter mentions that there are lands in Brazil that plant a second crop (safrinha crop). It is well documented that such double cropping patterns are not unique to Brazil and exist around the world wherever possible. This agricultural practice is not a new phenomenon and one can assume with certainty that their production outputs are captured in Brazil’s national agricultural statistics and included in the input-output national account matrices in GTAP. Furthermore, we agree with a suggestion that a higher resolution estimation of land use change in Africa is needed. But, the total productivity and land use change effects in that area of the world are much smaller in magnitude to the US or Brazil, resulting in very little change in the overall results. Thus,

based on the best available information and professional judgment of those with experience in these areas, the modelers selected the elasticity values. The elasticity of crop yield with respect to area expansion selected were 0.50 to 0.75 to account for parameter variability. In one of the five sensitivity model runs for sugarcane, the elasticity value of 0.80 was also chosen for Brazil. The final average value for carbon intensity was estimated by using those various elasticity values. To address such concerns, the Board has directed the Executive Officer to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified.

Crop Yield Elasticity

L-50. Comment: Crop yields - At least for the corn and sugarcane models, yield averages from the 2006-2008 crop years were substituted for the 2001 crop yields as there as been significant increases in US corn and Brazilian sugarcane yields between 2001 and 2008. There are two main issues here. First, all crop yields should be treated the same. Yields of other crops have also increased in this time period and it's not clear that higher sugarcane yields are included in the corn model and vice versa. Second, yield is a time-dependent variable with the values increasing in a predictable manner over time. Rather than selecting crop yields at a specific year some form of time averaging should be used to pick a representative yield over the time in question. Using 2006-2008 yield averages is likely to underestimate crop yields in the 2010 to 2020 period covered by the LCFS. (MONSANTO)

Comment: The Staff Report suggests that the GTAP results on sugarcane land use change were updated to reflect the 8.2 percent increase in Brazilian sugarcane yields observed between 2001 and the average for the 2006-2008 time period. However, the physical yield of the sugarcane plant is not the only source of yield gains in the production of sugarcane ethanol. The yield gain in Total Recoverable Sugars (TRS) should also be taken into account. According to the Ministry of Agriculture, Livestock and Supply (2007), the TRS per ton of sugarcane was 138.7 in 2001 and 149.47 in 2006 - an increase of 8.3 percent. (We note that this result would be even higher if official data for 2007 and 2008 were already available.) When the correct values for the ethanol size shock, the elasticities of substitution and crop yield, and the adjustment for sugarcane TRS is used, the indirect land use change emissions are 25.3 gCO₂/MJ, about half the value proposed in Table IV-12 of the proposed regulation. CARB staff has explained to us that the uneven application of elasticities was not on purpose but a result of having spent too much time trying various corn scenarios. As a consequence, the staff informed us, the modelers generated more runs and were able to figure out that the 0.25 for crop yield elasticity was a "better" value to assume. From a modeling testing and calibration perspective, it is easy to understand the pressure and various runs. Nevertheless, there remains no

credible explanation as to why the "better" choice about elasticities was not applied in the same way across alternative biofuels feedstock scenarios. Uneven application of the model parameters yields results that should not be used. (UNICA)

Comment: The second obviously is the scientific part of it and the assumptions that go into a model. And we've all talked about that. And we have some concerns about the values that go into that model and the values that are coming out. And with respect specifically to lignocellulosic ethanol, that we know that there are some errors in the assumptions of yield per acre, for example, that really affect the land use as it is applied to lignocellulosic ethanol. (VERENIUM)

Response: The change that most significantly affects model output is an increase in crop yields. In 2001, the average corn yield in the U.S. was 138.2 bushels per acre (55) and the average corn yield for 2006 to 2008 was 151.3 bushels per acre which represents a 9.5 percent increase over 2001. We used a three year average because yields can fluctuate significantly on a year to year basis. An adjustment for this yield increase was applied to the model results." Furthermore, the elasticity values that modelers used were based on literature information. The Board has directed the Executive Officer to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified.

Elasticity of Land Transformation across Cropland, Pasture, and Forestry

L-51. Comment: Confounding the problem further is the difficulty of determining additionality. Even if one assumes that biofuel production is the proximate cause of a certain amount of deforestation, one cannot assume that those forests would have otherwise remained intact in the absence of biofuel production. There are many causes of deforestation and land use change - timber demand, livestock grazing, mining, urban sprawl, global food and feed demand, and subsistence activities. People continually seek to realize the highest value from the land. If biofuels are removed as a market driving factor, other factors will likely fill the void. In sum, using these models to calculate indirect emissions remains a highly subjective and speculative process, dependent on a number of a priori assumptions that bias the outcome. (EES1)

Comment: CARB results suggest that the pasture land is being replaced by sugarcane and other crops, and that pasture land is advancing onto forest areas. This anomaly in CARB results may be due to the small elasticity of crop yields with respect to area expansion, which requires significantly more pasture area to place a new sugarcane plantation or recover the displaced production of other crops by sugarcane. Changes in GTAP parameters lead to strong reductions in land converted as a result of sugarcane expansion, but also the inclusion of the carbon uptake in forest gained and crops expansion may revert carbon

emissions to carbon uptake. Pasture yield price elasticity in Brazil is 0.6, much higher than the crop yield elasticities used in the GTAP scenarios presented in the CARB staff report. CARB should take into consideration the higher elasticities of substitution among primary factors in the livestock production sector in Brazil, where livestock intensification is potentially high and is an occurring practice. (UNICA)

Comment: The LUC models do not seem to have the capability to track how the converted lands are used after their conversion, especially those outside the U.S. For example, if the expansion of corn ethanol in the U.S. causes certain acres of a land to be converted elsewhere in the world, by definition, corn ethanol in the U.S. would carry an indirect burden of carbon intensity from that land conversion. However, if the converted land is then used to grow biomass for fuel production, this carbon intensity should be directly accredited to the fuel product, instead of being indirectly allocated to U.S. corn ethanol. Our concern is that without better definition of terms and in the absence of a defined "baseline year", there is the potential for double counting of LUC impacts. (CONOCO)

Response: The elasticity values that modelers used were based on literature information. Based on the professional judgment of those with experience in this area, the modelers selected a value if not enough information was available in literature. Because the available evidence indicates that land use changes across agricultural, forest, and pasture cover types are not readily triggered by changes in land costs, the elasticity of land transformation across cropland, pasture, and forestry was set to the relatively low value of 0.2 and for the sensitivity analysis it was varied between 0.1 and 0.3. To address concerns, the Board has directed the Executive Officer to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified.

Baseline for Ethanol Should Start in Year 2010

L-52. Comment: Ethanol production - Ethanol production is assumed to be 1.5 billion gal/yr at the beginning of the period modeled. This appears to be due to the selection of 2001 as the baseline year in the Global Economic Model. However, this is inconsistent with the assumption that 2010 gasoline will have 10 percent ethanol and the observation that 9.2 billion gallons of ethanol were produced in 2008. Rather than using 2001 ethanol production levels as the baseline, ethanol production at the start of the LCFS should be used as the starting assumption. Using 2001 as the baseline year appears to be back charging prior production increases to ethanol produced in 2010 and beyond.

Comment: Global Economic Model - 2001 was used as the base line year in the global economic model. This is stated as "The 2001 GTAP database builds on the most recent global harvested crop land and land cover data base

representing the combined efforts of the United Nations Food and Agricultural Organization (UN-FAO), the International Food Policy Research Institute (IFPRI) and the University of Wisconsin Center for Sustainability and the Global Environment (SAGE)". This is a technical requirement for the model, but does not justify the selection of 2001 ethanol production levels as the baseline assumption. Rather 2010 ethanol production levels should be used if "the carbon intensities of gasoline and diesel transportation fuels in 2020 are each reduced by 10 percent relative to 2010."

Comment: Value selection for time-dependent variables is inconsistent. The model for land use change proposed by CARB contains several important variables that change over time. However, the GTAP model requires single values for many of these. Selection of some of the single values appears to be inconsistent with the intent of the Low Carbon Fuel Standard and also somewhat arbitrary. According to the CARB Staff Report "Proposed Regulation to Implement the Low Carbon Fuel Standard Volume I", the California Low Carbon Fuel Standard requires incremental reduction in the carbon intensity of fuels such that "The allowable carbon intensity of transportation fuels decreases each year, starting in 2011, until the carbon intensities of gasoline and diesel transportation fuels in 2020 are each reduced by 10 percent relative to 2010." This suggests that 2010 should be selected as the baseline year. A closer look at the land use change model used by CARB shows that a number of different years are being used for baseline values. (MONSANTO)

Response: Staff was aware at the outset of the modeling effort that using 2001 as the baseline year was a limitation. The reason that GTAP employed the 2001 world economic database as the analytical baseline is that this was the most recent year for which a complete global land use database existed as of the time of analysis. However, it would have been erroneous to use the 2001 world economic database as a baseline year, in conjunction with some estimated production level for biofuels feedstocks in 2010. GTAP modelers correctly adjusted the corn yield from the baseline year to the average yield for the years 2006 through 2008. This is the latest period for which actual production and yield data were available for ethanol feedstocks. A three-year average was used to dampen the effects of any short-term fluctuations. We agree that crop yields will likely increase in the future and that this will reduce the land use change impact of using crop-based feedstocks for biofuel production. However, our lifecycle assessments are designed to reflect current technology and agricultural practices and are not meant to predict future technologies or practices. As production technologies and agricultural practices evolve over time, the fuel lifecycle assessments will be periodically updated to reflect these changes.

Sensitivity Analysis

L-53. Comment: CARB should use a more realistic projection of the increase in the demand of sugarcane ethanol from Brazil, taking into consideration aspects such as the total production capacity in place and the investments to expand the

production. CARB should perform a systematic sensitivity analysis of the alternative shock sizes, given the uncertainty about the incremental capacity in the next decades. (UNICA)

Comment: In light of these uncertainties, one would expect the Staff Report to present an extensive sensitivity analysis of each of the assumptions underlying the GTAP parameters. While the Staff Report refers to some sensitivity results, it does not present sufficient details to enable validation of the GTAP modeling. Commenter recommends that extensive sensitivity analyses can be performed. (NOVOZYM)

Response: The Purdue/UCB team ran numerous sensitivity runs for biofuels. At the end, seven sensitivity runs for corn ethanol and five sensitivity runs for sugarcane ethanol remained following the exclusion of runs outside the appropriate ranges. The sensitivity analyses were done in a very systematic way, in accordance with the acceptable economic theory. For example for corn ethanol, a production increase of 13.25 billion gallons was assumed for all but one of the modeling runs. This production increment corresponded to increasing U.S. corn ethanol production from 1.75 billion gallons in produced 2001 to the 15 billion gallon volume authorized by the Energy Independence and Security Act of 2007 (EISA). The sensitivity of the model output to this parameter was assessed by performing a run in which the ethanol production increase was set at 8.25 billion gallons. As noted in the Staff Report, the model proved very insensitive to the size of production shock for corn ethanol. To address such concerns, the Board has directed the Executive Officer to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified.

Predictive Power of the Model and Ground-Truthing

L-54. Comment: These models also often represent an agglomeration of parameters cobbled together from a variety of different sector-specific analyses. After several years of experience working with these models, a number of criticisms have emerged. First and foremost is the fact that an ex-post evaluation of the predictive power of these models reveals very weak empirical performance. Such models have also been criticized for their weak econometric foundations (see, for example, McKittrick (1998) and Jorgenson (1984)). The GTAP developers outline and discuss these very criticisms (Hertel et al., 2003). They note that the models are based upon price and substitution elasticities gathered from a variety of (mostly sector-specific, partial-equilibrium) time-series studies. These individual estimates do not represent precise statements of truth but rather are estimates subject to varying degrees of estimation error (e.g., standard errors of the estimates). As Hertel et al. (2003) note, CGE modelers typically take the point estimates as truth and ignore the uncertainty associated with estimation error. The end result are estimates and projections (such as those of land use

contained in this study) that have relatively unknown precision. As Hertel et al. (2003) note, “the confidence one has in various CGE conclusions depends critically on the size of the confidence interval around parameter estimates. Standard —robustness checks such as systematically raising or lowering the substitution parameters do not properly address this problem because it ignores information about which parameters we know with some precision and which we do not.” Hertel et al. (2003) also point to other criticisms of the GTAP modeling framework, which includes the use of inappropriate prices in estimation and the application of parameters taken from varying and potentially inappropriate levels of aggregation. (NCSU)

Comment: This is due in part to the fact that the model that is being used was not designed for this type of analysis. Also, it takes time to ground truth the results and ensure accuracy and we do not believe the staff at CARB had time to do this. Due to the uncertainty of the data and models and without appropriate time to ground-truth the data, defer the incorporation of indirect land use numbers until the quality of the data can be improved by involving experts in the field and until indirect land use can be determined for all fuels and energy sectors. (ILCORN)

Response: The LCFS GTAP model contains tight theoretical specifications and unlike other classes of economic models, it can provide insights into changes for which there is no historical experience. In general, validation of computable general equilibrium (CGE) model results is a difficult undertaking. CGE models report only the specific, incremental effects of the change or perturbation being modeled (e.g., increased demand for biofuels). Real world data on very specific, incremental effects such as these almost never exists. Data on exports, land conversion, caloric intake, trade volumes, etc. exist, but they consist of aggregate numbers: they reflect the net effect of many, often competing factors. The individual effect of any one factor usually cannot be teased out of them. The Board has directed the Executive Officer to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified.

Inadequacy of Sensitivity Analyses

L-55. Comment: The land use change carbon intensity values proposed by the Board were chosen from a very small number of scenario runs—seven for corn and five for sugarcane ethanol. The standard practice is to conduct a large number of runs varying the input parameters sufficiently to obtain the probability distribution of key input variables. This analysis should be run as to yield confidence intervals around the point estimates obtained. Given the level of uncertainty over many of the input parameters, a full sensitivity analysis is even more critical. ARB’s approach was scientifically weak and legally questionable. The number of scenarios run, and the elasticity combinations used in those runs, should be the

same for all fuels evaluated. Due to the uncertainty about the future supply of biofuels, ARB should perform a full sensitivity analysis on the size of the fuel production increase. (UNICA, WSPA1, RFA2, NOVOZYM1, 111SCIENTISTS).

Response: The Board acknowledges that the sensitivity analyses performed on its GTAP model runs were somewhat abbreviated. Although the total number of sensitivity runs performed somewhat exceeded the numbers cited in this comment (only the runs based on the most reasonable elasticity values were discussed in the ISOR), formal sensitivity analyses, leading to probability and uncertainty distributions were not performed. These were not possible given the time and resource constraints under which the LCFS land use change team worked. Nevertheless, the ARB staff are confident that the sensitivity analyses presented to the Board were sufficiently robust and provided reasonable range of results for Board's decision making. In recognition of this, and other sources of uncertainty, the Board adopted a conservative (low) land use change carbon intensity increment for corn ethanol, and directed staff, in Resolution 09-31, to form an Expert Workgroup to continue studying the land use change phenomenon, and the available approaches to measuring it. This Workgroup is likely to take up the issues of sensitivity and uncertainty analysis.

L-56. Comment: The Staff Report acknowledges the sensitivity of its GTAP results to crop yield elasticities, land-use transformation elasticities, and trade elasticities. (NOVOZYM1)

Response: This comment is not an accurate reflection of the actual sensitivity values reported in the ISOR (Staff Report). That document discussed the GTAP's sensitivity to six model input parameters. The model was found to be insensitive to variation in three of those parameters:

- a. The size of the ethanol production increase.
- b. The elasticity of harvested acreage response, which captures the extent to which the number of acres devoted to a crop will change in response to an increase in the cost of land (the cost of land being a reflection of crop commodity prices).
- c. Trade elasticity, which quantifies the extent to which importers will respond to a price increase from a given exporter by switching to a different exporter for the more expensive commodity.

The GTAP was found to be moderately to highly sensitive to the following three elasticities:

- a. The crop yield elasticity, which quantifies the relationship between commodity price and yield.
- b. The elasticity of land transformation across cropland, pasture, and forestry, which captures the extent to which an increase in the number of acres devoted to a crop will result in the conversion of pasture and forest land to agriculture.

- c. The elasticity of crop yields with respect to area expansion, which quantifies the yields that will be realized from newly converted lands relative to yields on acreage previously devoted to the crop of interest.

Details on the Board's GTAP sensitivity analyses can be found in Appendix C of the ISOR.

Static versus Dynamic CGE Models

L-57. Comment: A static CGE model is incapable of capturing critical changes that occur through time. ARB should analyze ILUC using a dynamic model. (NCGA, MONSANTO, PEERREVIEW3, 111SCIENTISTS, ABCINC, PRX)

Response: ARB chose the GTAP model (a computable general equilibrium or CGE model) for several reasons which are outlined in Chapter IV of the ISOR. As stated on page IV-46 of the ISOR:

The GTAP has a global scope, is publicly available, and has a long history of use in modeling complex international economic effects. Therefore, ARB staff determined that the GTAP is the most suitable model for estimating the land use change impacts of the crop based biofuels that will be regulated under the LCFS. The GTAP is relatively mature, having been frequently tested on large-scale economic and policy issues. It has been used to assess the impacts of a variety of international economic initiatives, dating back to the Uruguay and Doha Rounds of the World Trade Organization's General Agreement on Tariffs and Trade. More recently, it has been used to examine the expansion of the European Union, regional trade agreements, and multi-national climate change accords.

ARB acknowledges that static CGE models are limited by their reliance on static baseline parameters such as long-term crop yields (short-term, price-driven yield changes *are* accounted for using a yield elasticity parameter). The GTAP produces a single result based on a single changed condition (an increased demand for ethanol, for example), without respect for the time period over which the global economy returns to equilibrium following the introduction of the change. Equilibrium could return in less than a year, or over a period of several years. If the latter, it would be best if each year could be modeled individually (dynamically) using input parameters specific to that year. ARB discusses this limitation on page IV-46 of the ISOR:

GTAP uses the 2001 world economy as a baseline and does not account for changes that have occurred over the past eight years. The change that has the most significant effect on the land conversion estimate is the increase in crop yields since 2001. An increase in crop yields will lead to a corresponding decrease in land conversion. In response to this stakeholder concern, ARB staff and GTAP modelers have adjusted the land conversion estimate to account for

the observed increase in crop yields. This adjustment was made to the model results rather than within the GTAP itself.

Stakeholders are correct in stating that a dynamic model could account for changes in technology, agricultural practices, population, etc which occur over time. However when land use change modeling was initiated for the LCFS, no dynamic model was available that was comparable in quality to GTAP and adequately met ARB's criteria for selection (e.g. global scope, public availability, and history of use in modeling complex international economic effects).

At the April 23, 2009 hearing, the Board approved the use of GTAP to evaluate worldwide land use conversion associated with the production of crops for fuel production. The Board also acknowledged in Resolution 09-31 that the available methods for estimating indirect impacts (including land use change) are relatively new. In recognition of the relatively recent development of LUC analytics, the Board directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. The Board will strongly consider the findings of the workgroup in its continuing efforts to refine the LUC assessment. In approving the LCFS, however, the Board found that current uncertainty levels are not sufficient to call into question the existence of significant indirect land use change impacts.

L-58. Comment: GTAP is a static model that does not include a time element, and is based on 2001 data which does not reflect current conditions. In essence, this means the model is stuck in 2001 and must be shocked to achieve the desired conditions. Because of this, the model is unable to account for the significant improvements in grain yields that have occurred since 2001, and are projected to continue through 2015 and beyond. (NCGA)

Comment: Yields should be treated as a time dependent variable, similar to the way emissions due to indirect land use change are treated. (MONSANTO)

Comment: The lack of a time dimension in GTAP results in an awkward match with the question at hand. Corn yields have been increasing largely linearly for some time now in the United States, yet the model appears to use 2008 corn yields to determine land impacts of corn-derived ethanol. The projected steady increase in use of corn for ethanol in the US over the next few years suggests that land use change will be somewhat less than projected here. (PEERREVIEW3)

Response: The Board agrees that crop yields will likely increase in the future and that this will reduce the land use change impact of using crop-based feedstocks for biofuel production. However, our lifecycle assessments are designed to reflect current technology and agricultural practices and are not meant to predict future technologies or practices. As production technologies and agricultural practices evolve over time, the fuel lifecycle assessments will be periodically updated to reflect these changes. The

two mandated program reviews in 2011 and 2014 as well as subsequent program reviews will facilitate these updates.

It should be noted, however, that the model is not ‘shocked’ to overcome its use of a single baseline agricultural yield value. The ‘shock’ administered to the model is an increase in the production of ethanol. This causes markets to move away from equilibrium. The changed conditions that occur across the economy when markets find new optimal equilibrium points constitute the model’s outputs. See response to Comment L-57.

L-59. Comment: The Science Is Far Too Limited and Uncertain for Regulatory Enforcement. ARB staff is proposing to enforce a penalty on all biofuels for indirect land use change as determined by a computable general equilibrium (CGE) model called GTAP. This model is set to a static world economic condition (e.g. 2006), then shocked with a volume of biofuel to create the perceived land conversion result. The modeling outcome is applicable to the set of assumptions used for that particular run, but is not particularly relevant when there is a shift in policy, weather, world economic conditions or other economic, social or political variables. For example, by definition, these models assume zero innovation, which means they could not have predicted the 500 percent increase in corn yields since 1940, the tripling of wheat yields since 1960, or the 700 percent increase in yield that can occur if farmers in developing countries adopt higher yield seed varieties and more efficient farming practices. This inability to predict innovation is not limited to agriculture; similar attempts to use economic equilibrium models in other emerging markets like telephony or computing would have been equally unsuccessful. (111SCIENTISTS)

Response: The Board agrees that crop yields will likely increase in the future and that this will reduce the land use change impact of using crop-based feedstocks for biofuel production. However, our lifecycle assessments are designed to reflect current technology and agricultural practices and are not meant to predict future technologies or practices. As production technologies and agricultural practices evolve over time, the fuel lifecycle assessments will be periodically updated to reflect these changes. The two mandated program reviews in 2011 and 2014 as well as subsequent program reviews will facilitate these updates. See response to Comment L-57.

L-60. Comment: The ARB should recognize the GTAP model’s major weakness—that it assumes supply and demand are always in equilibrium. The ARB should address this shortcoming by adding a component to the model that can account for increasing yields, which would allow the model to show greater supply than demand over the long-term. Since substantial data exists showing supply and demand in the agriculture industry are never in balance, it is difficult to understand why the ARB would use this model for long-term forecasting. (Notably, one of the ARB’s own peer reviewers made this same point in his recent response to the draft regulation by stating that GTAP should not be used for forecasting periods longer than 15 years). This limitation of the GTAP model

is precisely why the ARB was unable to verify its ILUC model against 2001-2007 corn data. Of course, this is not entirely unexpected since the GTAP model was never intended for the purpose for which it is being used by the ARB. (ABCINC, PRX)

Response: Although it is true that supply and demand don't usually stay in equilibrium very long, it is true that the economy is always moving toward equilibrium. That is what allows models like the GTAP to make accurate predictions. The agricultural sector like other sectors of the economy reach state of equilibrium, and then undergo a perturbation that moves it away from equilibrium, but then returns to equilibrium. This is a sufficient approximation of what actually happens in the real economy.

ARB acknowledges that, in general, validation of computable general equilibrium (CGE) model results is a difficult undertaking. CGE models report only the specific, incremental effects of the change or perturbation being modeled (e.g., increased demand for biofuels). Real world data on very specific, incremental effects such as these almost never exists. Data on exports, land conversion, caloric intake, trade volumes, etc. exist, but they consist of *aggregate* numbers: they reflect the net effect of many, often competing factors. The individual effect of any one factor usually cannot be teased out of them. The GTAP predicts that increased demand for ethanol will reduce corn and soybean exports, for example. The fact that aggregate corn and soybean exports actually rose over the period that was modeled is irrelevant. It just indicates that the factors tending to drive exports up (among them, rising meat consumption driving an increasing demand for livestock feed) tended to compensate for the downward pressure from the diversion of corn to ethanol production. Regardless of the actual aggregate trend in exports, it was lower than what it would have been in the absence of that diversion of the corn crop. Despite these difficulties, however, the GTAP, unlike most other CGE models, has been subjected to validation studies. The results of these studies have been used to improve and refine the model. See response to Comment L-57.

L-61. Comment: To gage the hypothetical nature of CARB staff's use of GTAP 2001, consider the following questions: Would a complete but static economic database for the year 1941 be expected to accurately model land use changes during World War Two, 1942-45, and during the Marshall Plan re-construction and Soviet Iron Curtain conditions which followed the war? Would similar static economic data for the year 1961 be expected to model land use changes in Central Asia undertaken by Soviet-era agricultural planners? Would static economic data for 1981 be expected to model land use changes in the United States promulgated by Congress and USDA in Acreage Reduction Programs (ARPs) of tens of millions of acres, and in the Conservation Reserve Program (CRP), which grew to over 30 million acres? Thus, would static economic data for 2001 (and/or before) be expected to model land use changes following in the wake of the terrorist attack on the Twin Towers, the invasion of Afghanistan and Iraq, the emergence of China and other parts of Asia as fully industrialized and rapidly growing economies, the quadrupling of crude oil price, the investment

bubble in US real estate (including farmland), the creation of tens of trillions of dollars of new financial derivatives, and the subsequent collapse of the world economy? A reasonable answer to all of these questions would be "No." (PRX)

Comment: The CARB staff should note as well that if the data regarding the world's major ten row crops is a meaningful proxy for what has actually happened since 2001, compared to what was modeled from GTAP2001, then the fact is that this land use change has indeed already happened. It has been driven by crude oil price-or perhaps by the combination of all energy price increases in the context of world economic growth and the recent financial bubble-but it has happened. There is no practical point in assessing a penalty to corn ethanol or any other biofuel for the veritable "volcano" of land use change in row crops which has already happened. It is a change driven not by the (seemingly modest) RFS policy, but by the throes of the world economy under pressure of increasing energy price and financial instability. The proposed regulations should be based not on a static interpretation of past economic elasticities but on the dynamic prospective interaction of many variables. (PRX)

Response: The GTAP is designed to isolate the independent effects of a carefully specified change to single economic condition—an increase in the demand for corn ethanol, for example. All other conditions (such as those mentioned in this comment) are held constant. In this way, the model estimates the incremental impact of one changed condition, holding all else (such as oil price fluctuations) equal. This is how the GTAP is able to model the price-driven effects of a single change against a backdrop of stable long term conditions. The advantage of this approach is that it allows the incremental effects of a single, well-defined cause to be estimated in the absence of changes in competing and confounding causes.

For the results obtained to be valid, however, the long-term baseline conditions assumed to be stable over the period that is modeled must actually be relatively stable over that period. In the case of the LCFS corn ethanol analysis, many commenters pointed out that baseline corn yields were, in fact, not stable over the period modeled. In response, staff adjusted that baseline to reflect more current yields. To date, no other baseline condition relevant to the land use change effects being estimated have been found to have changed significantly. Should such changes come to light, the Board will undertake the appropriate revisions.

As mentioned in the response to Comment L-57, when a dynamic land use change modeling method that is otherwise as well-suited to LCFS impact assessment becomes available, the Board will consider adopting that method.

See response to Comment L-57.

Individual Facility Studies

L-62. Comment: Studies of a single ethanol plant in Illinois (operated by Illinois River Energy, LLC) have shown that it did not stimulate any land use change. All additional demand for corn was met regionally by increased yields. The Illinois River Plant is representative of approximately three billion gallons of ethanol production capacity constructed nationally since 2006. The lifecycle assessment performed on the plant is consistent with the requirements established under the Energy Independence and Security Act of 2007. The divergence between the results obtained by the Board and the Illinois researchers is attributable to the significant uncertainty in the Board's analysis. That uncertainty is due to the macro nature of the analysis. (ILCORN, IRELLC)

Comment: Land use change practices vary from region to region and regions also differ in their inherent ability to absorb increased production without undesirable land use change (NFA1).

Response: It is not inconceivable that the corn demands of a single ethanol plant could be met by increased regional yields alone. The extensive research that went into the creation of the GTAP model indicates, however, that—on a national scale—the diversion of corn to ethanol production does generate the need for additional agricultural land. On average, about a third of an acre of new land is required for every acre of corn diverted to ethanol production. At this time, the GTAP analysis used to estimate land use change impacts produces a single value that is applicable to all sources of a given fuel. Custom land use change values are not currently generated for individual fuel plants.

The commenters point to the uncertainty associated with the Board's GTAP results. It's important to note, however, that the Illinois River Plant study also encountered significant sources of uncertainty. Even though the study consisted of only the area within a 40-mile radius around the Illinois River plant, a full accounting of the causes behind the observed cropping changes was apparently not possible. Aggregate crop acreage changes were quantified with precision: corn acreage increased by 261,574 acres; soybean acreage decreased by 299,365 acres; a land area only 0.28 percent the size of the total number of acres in corn in the study area was converted from non-agricultural to agricultural uses. The researchers found, however, that these acreage changes were only partially caused by the ethanol plant's corn requirements, and that "other variables such as economics and high export demand may drive corn intensification." Potential effects beyond the study area were not discussed.

Complexity of Land Use Change Causation

L-63. Comment: Land use changes occur as a consequence of multiple nested policy and socio-economic variables. An article published in *BioScience* magazine¹⁹ captures the complexity of this process, as it relates to deforestation: "[a]t the underlying level, tropical deforestation is ... best explained by multiple factors

¹⁹ Helmut J. Geist and Eric F. Lambin, "Proximate Causes and Underlying Driving Forces of Tropical Deforestation", *BioScience Magazine*, Volume 52, No. 2 (Feb. 2002)

and drivers acting synergistically rather than by single-factor causation, with more than one-third of the cases being driven by the full interplay of economic, institutional, technological, cultural and demographic variables.” This review of land change science concludes that it has proven difficult to achieve a theory of coupled land use changes that lead to useful, predictable outcomes for this highly complex process. Similar approaches have led to strikingly different outcomes depending on location, scale and other complex factors, making prediction uncertain. It is worth noting that most primary forest deforestation is occurring in places like Brazil, Indonesia, and Russia as a direct result of logging, cattle ranching and subsistence farming. The domestic biofuels industry should not be held accountable for these types of land use change. (NFA1, ISU1, 111SCIENTISTS, NFA1, ABENGOA, NFA1, MONSANTO, ICM3, CERA1, DUPONT, ACE, NOVOZYM1, BIO, PRX)

Response: The Board agrees with the conclusion that it is not currently possible to identify and properly weight the full array of causes behind specific instances of land use change—let alone to ascertain the relative importance of each cause. This makes it extremely difficult to connect a cause, such as an increase in the production of biofuels in the U.S., to changes in land use around the world. The difficulty of tracing a single cause through a complex causal web to its effect does not, however, lead to the conclusion that the cause doesn’t exist. Instead, the difficulty of empirically connecting the cause to its effects makes the use of a robust and reliable model necessary. The strength of the model chosen by the Board to estimate land use change impacts (the GTAP) is that it is designed to hold all causal factors, except the one of interest—increased biofuels production, in this case—constant. The GTAP essentially disentangles this single cause from the many other drivers of land use change, and estimates its incremental impact. It is able to do this because almost all of the links in the chain of economic relationships that connect the cause to the effect have been quantified using data from empirical studies. Studies have confirmed, for example, that farmers respond to higher prices by increasing their production of the higher-priced commodity. Depending upon the size of the price signal, some farmers will increase production by converting new land to cropland. Despite the complexity of the decision process behind conversion events, very few tracts are converted unless those responsible are convinced that the conversion will yield economic benefits. The developers of the GTAP simply quantified the well-understood relationships (elasticities and coefficients) that drive this process, and built them into the model. The model, therefore, produces predictions that are consistent with well-understood and often-observed historical behaviors. The same considerations drive the location of land use conversion events in the model: as shown in the responses to the comments in section entitled, “Uncertainty of Land Use Change Emission Factors” (see Comment L-30, for example), land use change is predicted to occur in areas where it has historically occurred. This approach tends to control for the many nested and interdependent causes of land use change (whether they be proximate or distal). If the net effect of all those causes has tended to produce high rates of land conversion in a certain area, the model will predict high rates of change there as demand for the kinds of crops that can be grown there increases. On the other hand, if conditions have tended to discourage

land conversion in the past, projected future rates will also be low. In that historical trends are the product of the many forces that drive them, they also tend to serve as an effective proxy for those trends. The Board has concluded that this approach is capable of satisfactorily estimating impacts that cannot yet be empirically measured. The Board has, however, directed staff to create an Expert Workgroup to evaluate methodologies with the potential to improve the accuracy of its current land use change predictions. Any approaches with the potential for greater accuracy than those currently employed will be evaluated by the Expert Workgroup.

L-64. Comment: Because researchers have had difficulty establishing clear causal links between the increased production of biofuels and global land use change, the inclusion of a land use change increment in LCFS carbon intensity values will have virtually no influence on the course of land use change in the developing world or the associated GHG emissions. On the other hand, the nascent biofuels industry, if saddled with the GHG emissions generated by other sectors of the world's economy, will not be able to compete in energy markets. (ISU1, 111SCIENTISTS, NFA1, ACE, KVOLS).

Response: As shown in the response to the previous comment, a causal relationship isn't proven to be spurious just because it is difficult to empirically disentangle from a complex web of similar relationships. The research behind the development of the GTAP model, as well as other studies of the GHG impacts of biofuels, lead, in fact, to the opposite conclusion: significant increases in the production of biofuels does lead to land conversions which, in turn, lead to increased carbon emissions. Many of the responses in the section entitled "Unavailability of Land Use Change Estimation Methods" discuss this causal mechanism (see the responses to Comments L-1, L-2, L-17, and L-23, for example). To the extent that the production of biofuels causes forests and grassland around the world to be converted to agricultural production, therefore, the inclusion of a land use change increment in LCFS carbon intensity values *will* reduce the rate at which non-agricultural land is converted to agricultural uses. The impact of the land use change increment on the nascent biofuels industry will be to stimulate the development of lower carbon fuels that do not cause significant land use change. Fuels that are known to cause land use change will be "saddled" with the carbon intensity cost of that effect, but the ultimate effect will be to divert investment dollars to the development of other, less carbon-intensive, fuels.

L-65. Comment: In identifying lands that would be converted to agriculture due to the expansion of the biofuels industry, the GTAP does not consider existing and future policies designed to prevent undesirable land use change, or to preserve important habitat types. U.S. Federal biofuels policy, for example, contains provisions designed to discourage certain kinds of land conversion. (NFA1)

Response: The responses in the section entitled "Uncertainty of Land Use Change Emission Factors" discuss the land use conversion patterns modeled in the GTAP (see the response to Comment L-30, for example): future land conversion in all global agro-ecological zones follows established historical patterns. This is a reasonable approach

given that (a) areas protected by conversion limitations in the past will continue to show little or no conversion in future periods, and (b) unprotected areas, and areas that are subject to poorly enforced protections, will continue to show historical conversion rates in future periods. The Federal Energy Independence and Security Act of 2007 does mandate that the regulations implementing its provisions (the Renewable Fuels Standard) contain provisions limiting undesirable land use change (Title II, Subtitle A, Section 201, which contains language amending Section 211(o)(1)(H) of the Clean Air Act). To date, those regulatory provisions have not been finalized. When these, or any other policies with the potential to alter the course of agricultural land conversion, are implemented, the Board will appropriately evaluate them and modify current land use change algorithm as appropriate.

L-66. Comment: There is no verifiable correlation between deforestation in Brazil (due to expanding soybean production), and ethanol production in the U.S. In fact, as ethanol production in the U.S. rose sharply, deforestation declined markedly in Brazil. (GE3)

Response: The causal connections between expanded biofuel production in the U.S. and the conversion of non-agricultural land to agricultural uses globally is discussed in detail in the responses in the section entitled “Unavailability of Land Use Change Estimation Methods” (see the responses to Comments L-1, L-2, L-17, and L-23), as well as in the first response in this section (response to Comment L-63). One important point that bears repeating here is that the GTAP does not predict aggregate land use change anywhere. Aggregate deforestation trends in Brazil are irrelevant, and do not in any way call the Board’s land use change projections into question. Aggregate deforestation is driven by a number of factors: road-building and general accessibility, lumber prices, alternative economic activities that reduce pressures on remaining forests, etc. Food, feed, and fiber crop shortages (and resulting price increases) driven by the American biofuels industry is just one of the factors driving deforestation. If the factors that are tending to decrease the rate of deforestation are greater than those tending to increase it (such as the biofuels industry), then the net result will be a decrease in the annual deforestation rate. This aggregate decrease does not mean that the biofuels industry isn’t acting to stimulate the conversion of forest to agriculture—it simply means that this action is being counteracted by pressures in the opposite direction, resulting in a net decrease in the aggregate deforestation rate. One valid conclusion that can be drawn about the relationship between the American biofuels industry and declining deforestation rates in Brazil is that the rate of deforestation would be greater in the absence of the economic pressure exerted by the biofuels industry.

L-67. Comment: The reality of on-farm decision-making in the U.S. is far too complicated to be modeled by the GTAP. The model is simply not able to simulate the aggregate effect of farmers across the nation responding to a host of economic, policy-based, agronomic, climatic, and other signals. Similarly, global land use change is driven by forces that are too complex, numerous and interdependent to allow just one of them to be teased out and quantified. For example, the GTAP modelers purport to be capable of estimating the land use

change impacts of the ethanol production levels called for under the Federal Renewable Fuels Standard (RFS). All the model does, however, is “shock” a static representation of the 2001 economy with 13.25 billion gallons of ethanol, bringing total production, in one year, to the 15 billion gallons authorized by the RFS. However, under the provisions of the RFS production will increase steadily over several years, subject to regulatory adjustments and market realities. Congress specified, for example, that EPA set annual biofuel production levels as a percentage inclusion rate of ethanol, which is calculated in November for the following year, based on projected annual motor fuel consumption data from the Department of Energy's Short-term Energy Outlook for October. If the DOE's projection turns out to be above or below the actual motor fuel usage in the coming year, ethanol consumption will be above or below the mandate RFS levels, depending on the share of total motor fuel supplied by Small Refiners because the model does not even come close to capturing these complexities, and because it is being forced to project beyond the historical reach of its underlying data set, its results are merely hypothetical. They are in no way an empirical test of the land use change impacts of the Renewable Fuel Standard. CARB's modeling effort essentially attributes agricultural land use change since 2001 to increased ethanol production, when that land use change was actually driven by crude oil prices, other energy prices, general economic growth, and other factors. (PRX)

Response: Models, by definition, are simplifications of reality. Their purpose is to abstract from reality and quantify those forces which exert the greatest influence on the effect of interest (agricultural land use change, in this case). The test of a model's success is not how well it duplicates the actual complex fabric of reality, but how well it can estimate changes in the effect of interest based on changes to the forces exerting a significant influence on that effect. Modeled results will deviate from reality if (a) the wrong set of causal forces was built in to the model, and/or (b) the influences of those forces on the effect were incorrectly quantified. The GTAP modeling of the land use change impacts of corn ethanol, for example, was not intended to be a full scale simulation of the Renewable Fuel Standard. The regulatory intricacies of the RFS are irrelevant to simulation. All that is important is that the modeled world economy experience a significant increase in ethanol production. Subsequent sensitivity analysis showed that the actual size of the production increase was not important. The results obtained did not vary significantly when the production increase was varied. It is, likewise, not necessary for the model to capture the full complexity of the on-farm decision-making process. The primary driver of the decision to increase output is simple and well-understood: commodity prices. Very few farmers will expand production if that expansion is unlikely to be profitable, and very few will refrain from expansion in the face of favorable price signals. This is the essential decision process the GTAP captures. It is not hypothetical. It simply operationalizes what we have long known and understood about the relationship between commodity prices and production decisions made by farmers. Farmers in countries other than the U.S. respond to the same sets of price signals. If U.S. exports are less than what is demanded locally (due to the diversion of a larger proportion of the American corn crop to ethanol production)

then corn prices will rise internationally. Farmers who are able to will attempt to take advantage of that price increase by increasing production. Some will do so by planting on newly converted agricultural land. Many of the responses found in the section entitled “Unavailability of Land Use Change Estimation Methods” explain why the Board has concluded that the GTAP has successfully abstracted from reality and properly quantified the forces driving international land use change. Those same responses acknowledge that the current GTAP results are nonetheless more uncertain than the Board would like. Uncertainty will be addressed by an Expert Work Group to be convened in response to directives contained in Board Resolution 09-31.

Land Use Change Stifles Current and Next Generation Fuels

L-68. Comment: Conventional biofuels are a cornerstone for the development of advanced biofuels. The successful development and commercialization of second generation biofuels is largely contingent on market opportunities for first generation biofuels, which result in investor confidence, infrastructure development, and public acceptance. Enforcing uncertain land use change effects against conventional, crop-based biofuels will destabilize the conventional biofuels sector by eroding investor confidence and market certainty. This in turn will stifle development of advanced biofuels necessary for the California LCFS to be successful. Moreover, because lifecycle assessments have not been completed for advanced biofuels, investor confidence will further be eroded by uncertainty over the land use change effect to be applied to these second generation fuels. (NFA1, 111SCIENTISTS, SHELL, ABENGOA, TNSP, SUSCON, UCD2, BCC2, POET1, NOVOZYM1, NOVOZYM2, VERENIUM, MDV1, MDV2, ACE, GE3, ABFA, BIO, JMBM, MONSANTO, RFA2)

Response: The California LCFS does not affect the volumes of corn ethanol, biodiesel, cellulosic and other advanced biofuels mandated under the federal Renewable Fuels Standard. The Renewable Fuel Standard volume mandates guarantee market security for these biofuels. The California LCFS only provides additional incentive to produce those biofuels which are to be sold in California in the most sustainable manner.

It is also important to note that some biofuels will have little or no indirect land use change increment added to their carbon intensity values. The biofuel feedstocks that will be most affected by the indirect land use change increment are those fuels made from feedstocks that displace food, livestock feed, or fiber crops. Many cellulosic feedstocks displace little or no food, feed, or fiber crops. In response to Board directives found in Resolution 09-31, staff is currently preparing a table containing fuels and feedstocks expected to have little or no land use change impacts. This table will be included in a document entitled, “Establishing New Fuel Pathways Under the Low Carbon Fuel Standard: Procedures and Guidelines for Regulated Parties,” a draft of which is posted to http://www.arb.ca.gov/fuels/lcfs/fuels_pw_guidance.pdf. Examples of the feedstocks in this table are municipal and agricultural waste streams, cellulosic crops grown on marginal lands that could not support food, feed, or fiber crops, wastes from standard forestry practices (thinning, fire prevention, etc.), and cellulosic crops

grown between existing row crops, or added to existing crop rotations. The Board wishes to clearly differentiate these feedstocks from others, like corn, soybeans, and sugarcane, which are known to displace food, feed, and fiber crops. This clear differentiation should clear up most or all of the uncertainty about next-generation biofuels in the investment community.

The regulatory process for revising the LCFS carbon intensity lookup table—either adding new fuel pathways or changing existing pathways—is described in some detail in the “Establishing New Fuel Pathways” document alluded to above. Board Resolution 09-31 mandated this process in order to provide stability to the LCFS program by making the lookup table revision process formal, deliberative and fully public. Any decisions reached must fully consider all comments received, as well as any potential economic impacts. The Board must approve any revisions to land use change carbon intensity values. This process should provide the investment community with added certainty.

Co-products and Land Use Change

L-69. Comment: In developing the indirect land use change (ILUC) emissions values, CARB claims to have followed a “fair and balanced process.” We concur that CARB followed a fair and balanced process by holding workshops, developing draft materials and encouraging stakeholder input. However, we do not think CARB has arrived at a fair and balanced result; we think the 30 g/MJ is too high based on a number of factors. The following are our overall comments on the corn ethanol ILUC value:

- GTAP co-product land use credits result in overestimation of land use changes
- Other GHG benefits of co-products are ignored (or “still being evaluated”) (RFA1).

Comment: Among the major concerns we have with the GTAP modeling used to produce the results presented in the ISOR are: inconsistency of projected average grain yields and the period of the “shock”; underestimation of the significant land use “credit” provided by distillers grains (the feed co-product of grain ethanol); and assumptions on carbon emissions from converted forest. [Only the second item (land use credit) is the focus of this comment but the entire statement was included for clarity]. (RFA1)

Response: The letter from which this comment came voices two primary objections to the co-product credit component of the corn ethanol land use change carbon intensity value published in the LCFS ISOR (30 gCO₂e/MJ): 1) The use of a displacement ratio greater than 1:1 (used in the Board’s CA-GREET analysis) would reduce corn ethanol’s land use change impact estimate; and 2) the Board’s analysis doesn’t account for reduced methane emissions resulting from enteric fermentation in ruminants (ruminants such as cattle may experience shortened lifecycles when fed distillers’ grains). Related to item 2 is the criticism that the Board’s analysis didn’t account for reductions in the need for phosphorus supplements in the diets of livestock fed distillers’ grains.

Co-product credits and feed displacement ratios: Co-products are handled differently in GTAP and CA-GREET. In determining the direct lifecycle credit for distillers' grains, CA-GREET considers the nutritional characteristics of DDGS relative to the feeds for which it substitutes. CA-GREET then adjusts this nutritional analysis for certain physical limitations that are known to reduce the use of distillers' grains in actual livestock operations: quality variation, 'shelf life,' transportation costs, etc. The result of this analysis is a mass-based displacement ratio expressing how much traditional feed is displaced by distillers' grains. The Board is currently using a displacement ratio of 1:1, which the commenters consider to be too low (see Section M, "Coproducts and Coproduct Credits"). GTAP, on the other hand, uses feed substitution elasticities that reflect the relative ease with which distillers' grains substitute for other feeds in the different livestock rations. The model uses these elasticities, the relative prices of feeds, and changes in the size of the livestock industry to calculate a co-product credit. No "displacement ratio" is used in the GTAP model. The Board's GTAP modelers have estimated, however, that the feed substitutions that occurred in the GTAP corn ethanol analysis would equate to a displacement ratio somewhat higher than 1:1. In evaluating the co-product credit from GTAP, however, it is important to keep in mind that is completely independent of the distillers' grain displacement ratio used in CA-GREET. Increasing the CA-GREET ratio will have no effect on the GTAP-based co-product credit.

Reduced enteric fermentation and phosphorus supplements: The Board is currently considering a number of factors not considered in the analysis appearing in the ISOR. Some of these factors are likely to reduce the current land use change estimate, while others are likely to increase it. Reduced enteric fermentation and phosphorus supplements are among these factors.

For more details on co-products and co-product credits-please see Section M of this FSOR.

Food Vs. Fuel

L-70. Comment: CARB should update its food versus fuel analysis to show the significant influences of distillers grains co-products on the results. (RFA1)

Comment: CARB's food vs. fuel analysis should be updated to account for the contribution of feed co-products and the impact of yield improvements. (RFA1)

Comment: The ISOR poorly presents a food versus fuel analysis where the costs and benefits of a 50 million gallon ethanol plant operating in California are summarized. However, the analysis omits the benefits of the feed co-products, which greatly affects the land needed. It also affects the land converted, the release in GHG emissions due to land conversion, and the net GHG benefits. Also, to the extent CARB's land conversion estimates are too high, it also overstates the land converted. (RFA1)

Response: Biofuel production mandates in the U.S. and Europe will result in the diversion of agricultural land from food production to biofuel feedstock production. The Staff Report on page V-42 and Appendix C9 contain a brief illustration of indirect land use land requirement of a 50 million gallon ethanol facility in California. Although the co-product credit is included in the calculation, it is not explicitly shown. The example of a 50 million gallon ethanol plant was to provide a brief illustration of the potential impact of corn ethanol production on food prices. There are numerous references in the Staff Report about the way feed co-products credit is calculated. For example, page IV-12 has the following paragraph “The pathway from feedstock to final fuel production and use involves several processes and operations. These processes have the potential to generate products besides the primary fuel of interest. These additional products are termed co-products. For a current generation ethanol plant, a co-product produced is dry distiller’s grain solubles (DDGS). This can be used as a replacement for traditional feed for livestock. A complete lifecycle analysis requires an appropriate GHG credit be provided to the pathway since the use of this co-product will displace the need to produce the displaced product. For corn ethanol, DDGS could replace feed corn that is used as animal feed. The model therefore has provided a GHG credit to the pathway equivalent to producing 1 lb. of feed corn for every lb. of DDGS produced. Appendix C has details of co-product crediting methodologies used in the lifecycle analysis.”

For more details on food versus fuel-please refer to Section H of this FSOR.

Joint Price Elasticity of Ethanol and DDGS

L-71. Comment: The rapid expansion of corn-based ethanol in the U.S. in the past few years, driven by an aggressive biofuels policy, has transformed the demand for the raw product corn. Like its competitor in acreage, soybeans, a large component of U.S. corn demand should now be considered to be the raw input into the joint product of ethanol and dried distillers’ grains (DDG’s). This property means that the price elasticity of demand for the basic input (corn) is a weighted average of the price elasticities of the joint products (ethanol and DDG’s) (Houck 1964). This transformation, combined with several years of a lower U.S. dollar which has increased the demand for US exports of corn (corn export demand increased 52.3% from 2002 to 2007 totaling 2.425 billion bushels (19% of total use)), has meant that the total demand elasticity for U.S. corn has become a more complex relationship involving total demand elasticities rather than domestic elasticities (Piggott and Wohlgenant, 2002). Taking account of these relationships is critical when evaluating how current biofuels policies impact demand and the elasticity of corn demand is in play. (NCSU)

Response: To answer the above question, ARB contacted Farzad Taheripour, an Energy Economist in the Department of Agricultural Economics at Purdue University. Professor Taheripour is one the main biofuels GTAP modelers who has worked to incorporate ethanol and its co-products into the GTAP model. Dr. Taheripour does not support using the weighted average of the price elasticities of the joint products of only

ethanol and DDGS to represent the price elasticity of demand for the basic raw corn. Here is an excerpt of his explanation. GTAP ethanol and dried distillers grains (DDGS) are two distinct commodities, with their own respective markets. It is those markets that determine the price elasticity of demand for the respective commodities. For example, ethanol is mainly used as an additive to gasoline in the petroleum sector of the economy, and a portion of that is used by final consumers. On the other hand, DDGS is mainly used in the animal products/livestock sector of the economy and a portion of that is exported to other countries for livestock feed. It is true that changes in the demand for these commodities might change the demand for corn, but, the demand for corn has other components, such as demand for domestic food consumption or corn exports. To use a weighted average of the price elasticities of the joint products of only ethanol and DDGS to represent the price elasticity of demand for the basic raw corn is to disregard the other sectors that are consumers of corn demand such as domestic corn consumption and exports. The GTAP modelers tried to capture all components of the demand for corn. The total demand for corn is a combination of all types of demands for corn.

DDGS and Livestock Feed

L-72. Comment: Finally, the calculation of the net increase in corn acreage needed to meet the projected level of corn use for ethanol must recognize that 30 percent of the raw corn used for ethanol production is not consumed in the distilling process, but is available as a livestock feed. That availability substitutes for other feeds, including corn, reducing the acreage required for the production of those feeds. (UIUC1)

Response: In the GTAP model, by providing a co-product credit, it is recognized that 30 percent of the raw corn used for ethanol production is not consumed in the distilling process. In the model, livestock sector uses various inputs, including feedstuffs. Feedstuffs include various components, including coarse grains/corn and DDGS based feed composite. Coarse grains/corn and DDGS, are substitutes in the model. If the price of coarse grains rise faster than price of the composite, livestock producers move away from coarse grains/corn and toward DDGS. This is because DDGS substitutes for animal feed in the model. Therefore, the availability of co-products, i.e., DDGS in the GTAP model, means less land conversion.

Other Co-product Issues

L-73. Comment: Sensitivity analysis will be needed on co-product allocations, soil carbon payback assumptions, and possible food grain and water resource tipping points. In addition, there will be increasing need to differentiate averaged impacts with more precise marginal analysis. (SCAQMD1).

Response: While the Board decided that evaluations done by staff were adequate to proceed with approving the LCFS, Board Resolution 09-31 directed Staff to convene an

Expert Workgroup, which will consider the need to perform a number of analyses, including those listed in this comment.

For more details on co-products and co-product credits-please see Section M of this FSOR.

L-74. Comment: Staff includes a positive value of co-products of alternative fuels in their economic analysis - this appears to overstate their benefits, and reduce costs creating perception of value greater than what may be real. (CSBR2)

Response: As described in the response to the comments in Section K (“Lifecycle Analysis”) staff took a balanced approach to assessing the need to account for the greenhouse gas reductions resulting from the use of the corn ethanol co-product known as “distillers’ grains.” This approach reduces the likelihood of either over- or underestimating the greenhouse gas benefits of distillers’ grains used as livestock feed.

Indirect Effects Only Assessed Against Biofuels

L-75. Comment: Biofuels are not the only fuels with indirect emissions. Other fuels (e.g. gasoline, electricity, hydrogen) have indirect effects as well. Enforcing indirect effects against biofuel production only creates an asymmetry or bias in a regulation designed to create a level playing field. It violates the fundamental presumption that all fuels in a performance-based standard should be judged the same way (i.e. identical LCA boundaries). Enforcing different compliance metrics against different fuels is the equivalent of picking winners and losers, which is in direct conflict with the ambition of the LCFS. (ISU2, 111SCIENTISTS, NFA1, NCB, OCGA, ABENGOA, ILCORN, LEONARD, UNICA, IOWACORN, NCGA, TNSP, EDF2, JBI, MDSA, AGBC, SUSCON, SBCTC, BCC2, NFA2, BAYBIO, EESI1, PLS, VERENIUM, RFA2, JMBM, CACA1, UCD2, NFA2, ACE, GE3, ICM3, BIO, ACE, DUPONT1, WBIA, MDV1, GE3, USDGLLC, BIO, CO2STAR, SOI, MDV1, GE3, 2462-NOVOZYM1, ABCINC, ACE, WBIA, UCD2, MDV1)

Comment: Until the indirect effects of all fuels are evaluated, ARB should delay the LCFS or base the LCFS regulation on direct carbon effects only. (NFA1, ILCORN, IOWACORN, TNSP, JBI, SBCTC, BAYBIO, VERENIUM, WBIA, MDV1, GE3, ABCINC, WBIA, MDSA, OCGA)

Response: ARB identified indirect land use changes as a significant source of additional GHG emissions for some crop-based biofuels, and included the emissions associated with these changes in the carbon intensity values assigned to those fuels in the LCFS. Most scientific studies, including modeling performed for the LCFS, show that land use change effects for crop-based biofuels constitute a large percentage, and in some cases a majority, of the overall GHG emissions associated with fuel production and use.

ARB identified no other significant indirect effects that result in large GHG emissions that would substantially affect the LCFS framework for reducing the carbon intensity of transportation fuels. In addition, stakeholders have not provided any quantitative analysis that demonstrates that these impacts are significant. ARB concluded that excluding the indirect effects from the carbon intensity values of other fuels such as electricity and petroleum does not have any significant effect on the overall global warming potential of these fuels and does not substantially affect the assessment of the strategies and pathways that are likely to be used to comply with the regulation. But exclusion of the indirect effects from the carbon intensity values of some biofuels would give a completely erroneous assessment of the global warming potential and would introduce substantial errors in the assessment of the strategies and pathways that would likely be used to comply with the regulation. This would delay the development of truly low-carbon fuels, and jeopardize the achievement of a ten percent reduction in fuel carbon intensity by 2020. Therefore, ARB concluded that it is not unfair to include indirect effects for biofuels only at this time.

Some providers of crop-based biofuels continue to maintain, however, that significant market-mediated indirect effects other than land use change are likely to exist. Staff will continue to work with interested parties to identify and measure such effects. The Expert Workgroup will evaluate this issue, and its findings will be part of the report to the Board by January 1, 2011, and also included as part of the 2011 and 2014 reviews.

L-76. Comment: However, the proposed regulation unfairly disadvantages our company by overestimating our direct carbon emissions and selectively assessing indirect effects against ethanol while underestimating the direct emissions and ignoring the potentially significant indirect emissions of petroleum-based fuels. It also discriminates against our company because we do not have locations in California and we won't receive the more favorable treatment that California ethanol producers would enjoy. If CARB moves forward with this regulation, it will damage our existing business - effectively denying us access to the nation's largest market of liquid transportation fuels - and endanger our future plans. CARB should delay inclusion of an ILUC penalty against biofuels until the scientific community has had a chance to assess the indirect effects of all fuels, and it should continue to refine its accounting of direct effects based on the most recent data. (POET1)

Response: ARB is committed to an accurate accounting of GHG emissions and does not discriminate based on location of a company, either inside or outside of California. The carbon intensities of some California-produced fuels do benefit from shorter transportation distances and lower carbon intensity electricity sources.

ARB will continue to refine its accounting of the direct effects based on the most recent data. Mandated program reviews in 2011 and 2014 as well as subsequent reviews will allow for the updating of carbon intensity values over time to reflect improvements in data quality. More significant improvements in fuel production methods and associated carbon intensity values can also be addressed through the Method 2A process.

With regard to the portion of the comment concerning selective assessment of indirect effects and delaying inclusion of land use change emissions, please see the response to Comment L-75.

L-77. Comment: CARB should account for the indirect market effects of other fuels.

Response: CARB has already assessed land use changes from petroleum-based fuels which has been found to have an effect on the order of one percent, but has not seen data or modeling work showing significant indirect land use impacts. Also, CARB has undertaken some studies considering whether there are other significant effects associated with fuels. As part of this effort, CARB has requested that stakeholders provide additional information or studies that have identified indirect effects on other fuels. Finally, CARB is committed to continue to evaluate indirect effects associated with fuels that are incentivized by the LCFS.

L-78. Comment: The LCFS is not expected to change world crude oil prices. Even so, any avoided petroleum impacts would be credited back to the fuels displacing petroleum, not petroleum itself. (NRDC3)

Comment: GHG emissions from the electric sector are capped under AB32 and are expected to be capped federally soon. The same is true for most other significant sources of GHG emissions except land-use. As a result, the potential for economic factors to induce indirect emissions is greatly reduced. (NRDC3)

Comment: A complementary approach could be to cap the agriculture sector. However, there are no current plans to do such in the foreseeable future.

Comment: In comparison to the large effects from iLUC, NRDC's analysis shows that potential indirect, or market-mediated impacts, from these other fuels are likely small or insignificant as a first order estimate. That said, ARB Staff has reasonably committed to further evaluation and study of the potential indirect effects of other fuels. (NRDC3)

Response: ARB largely concurs with the commenter's analysis of the topic of indirect effects of other fuels. Please see response to comment L-75.

Fuel Shuffling

L-79. Comment: A California low-carbon fuel standard will simply divert higher-carbon fuels to other markets, resulting in no net greenhouse gas emissions reduction benefit. Fuels barred from California would simply be sold in states or foreign countries where controls are more lax. (NFA1, SHELL, CONOCO, WSPA1, CBE3, CNAES, LBA2)

Response: Carbon-reduction measures similar to the LCFS are under consideration at the regional, national, and international levels. The most significant of these measures are summarized in Chapter II of the Staff Report. Initiatives such as these are necessary to the achievement of meaningful, long-term fuel carbon reductions: without the wider adoption of fuel carbon standards, fuel producers are free to ship lower-carbon fuels to areas with such standards, while shipping higher-carbon fuels elsewhere. The end result of this fuel “shuffling” process is little or no net change in fuel carbon content on a global scale. For this reason, ARB seeks to establish a fuel carbon regulatory framework that is durable enough to be exported to other jurisdictions. The successful implementation of an effective framework in one jurisdiction should hasten the adoption of that framework elsewhere. Consequently, the Board in Resolution 09-31 directs the Executive Officer to coordinate efforts, to the extent feasible, with the US EPA, the European Union, and other regional, national and international agencies considering the adoption and implementation of an LCFS regulation or similar programs.

The LCFS Requires ARB to Regulate Land Use

L-80. Comment: The LCFS regulation will require the ARB to regulate land use, agricultural practices: such as when and how crops will be planted and harvested together with the overall usage of the land. (ERG1, ERG2)

Comment: The features of the (CARB) proposed regulation will hamstring the farmer and rancher landowners as the bureaucrats will dictate how and when crops will be planted and harvested together with the overall usage of the land. Is it possible to have employees of the State of California dictate to land owners (in far away places such as Imperial County, Modoc County, Lassen County etc.) how to implement their agricultural practices and management of the land? (ERG1)

Comment: The proposed Low Carbon Fuel Standard that is proposed by the California Air Resources Board may be the Straw that breaks the camels back. From what I read it appears that the Farming & Ranching community may have to petition CARB in order to continue the practice of farming. I would assume the employees of CARB who will oversee this regulation have Ph.D in Agronomics and possibly have the ability to provide the necessary financing and expertise when they oversee the crop planting, harvesting and overall land use. Suggestion only! Common Sense will save everyone a lot of grief. (ERG2)

Response: The LCFS contains no provision that would allow the ARB to regulate what happens on farms and ranches. The regulation would not require the ARB to regulate land use and agricultural practices. The regulation does require well to wheels lifecycle modeling in order to quantify the carbon intensity of motor vehicle fuels including biofuels. The inputs to this modeling used established factors for production of biofuels. The regulation also allows recognition of improvements to the production of such fuels, but does not mandate the improvements. To refine the land use change lifecycle

modeling, the Board in Resolution 09-31 directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis and to return to the Board no later than January 1, 2011, with regulatory amendments or recommendations.

L-81. Comment: The United Nations has determined that Ethanol from Sorghum is acceptable as an energy crop and according to their scientific data is responsible for a large reduction in CO2 emissions. Our CARB would regulate crops such as this without knowledge or foresight of their actions. (ERG1)

Response: The LCFS specifies the modeling to be done to quantify the carbon intensity of fuels. The LCFS allows producers to seek different values or to establish values for new fuels through Methods 2A and 2B. There is no regulation of crops. Currently, there is no sorghum ethanol pathway in the regulation. If interested individuals wish to make biofuels from sorghum, as stated by the Board Resolution 09-31, they can apply for a specific sorghum ethanol fuel pathway under the Method 2B.

Public Availability of Modeling Data

L-82. Comment: With respect to GHG modeling, the ARB mentions the words “full transparency” in the draft regulation on multiple occasions. We are pleased to state that this has been the case with regard to the direct emissions model, CA-GREET. To date, however, this has not been the case with respect to ILUC/GTAP modeling. ARB staff has indicated at public meetings that the GTAP model is publicly available. Unfortunately, this is only technically true because to gain access to the model one has to pay Purdue University a sum of approximately \$9,000. And even if one musters the financial resources to access the GTAP model data, he or she still would not know what assumptions had been changed by ARB staff and contractors because that information has not been made available to the public. Given the extreme importance of the ILUC modeling effort to the biodiesel industry and the fact that the ARB appears to be moving forward on this issue at a very rapid pace, we would hope all data related to this work would be made publicly available in the very near term so that organizations such as ours could participate meaningfully in the effort. As it stands currently, we have contracted with a noted expert in the field to analyze ARB’s work who is unable to do so because no significant information has been released. (ABCINC)

Comment: WSPA requests more details on the LUC numbers. How many acres of what type of land were converted for CBE (acres/100 gallons ethanol)? What are the effects of intensification on the efficiency of corn production and N2O conversion? Can ARB show these details in their backup document? (WSPA1)

Comment: In addition to the large uncertainties that CARB acknowledges, CARB's analysis is not sufficiently transparent to allow the regulated community to assess the accuracy of the indirect land use change factors that CARB is proposing. We urge CARB to provide additional information that will allow the regulated community to fully assess CARB's analysis of such a significant issue. (SHELL)

Response: The Board has a long standing policy to engage the public and stakeholders in formulating its regulations. ARB's adherence to an open regulatory development process was accomplished in part by staff conducting sixteen public workshops on the proposed LCFS regulation in 2008 and 2009. The announcements were posted on the ARB website and distributed through a list serve that included over 6,000 recipients. All materials presented at the workshops were also posted on the ARB website. Almost all of the meetings were telecast, available by teleconference, or both. The dates of the workshops and the materials presented at each workshop are available on the ARB website.²⁰

In cooperation with Argonne National Laboratories and the California Energy Commission, ARB staff hosted two special public training sessions on the CA-GREET model used to develop carbon intensities for the various fuel pathways. These sessions, held in the first quarter of 2008, were designed to provide stakeholders with a basic understanding of how the CA-GREET model worked. Training materials on these training sessions are also posted on the ARB website. Additional and very detailed hands-on training for about 10 stakeholders and agency personnel were also provided in the first quarter of 2008.

ARB staff has also participated in over 200 individual meetings with various stakeholders, supported by numerous individual telephone calls. All comments submitted through the entire process are posted on the ARB website.²¹ Over 200 individual comment letters were submitted either in response to the public workshops or to raise specific issues. In addition, the website contains a number of supporting documents that were related to the development of the LCFS.

Staff released its proposed regulation and the ISOR (Staff Report) for public comment on March 6, 2009. Over 200 comments were received during the 45-day public review period. In addition, 40 written comments and 90 oral testimonies were received during the Board Hearing on April 23, 2009.²² The scientific portions in the Staff Report of the proposed regulation were reviewed by four peer reviewers prior to the public hearing. None of the reviewers required a major modification to either the proposed regulation or the analysis used to support the proposal. The Board approved staff's proposed regulation, with modifications, after considering all comments received.

²⁰The dates and materials from the ARB workshops are presented at:
http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings.htm.

²¹ All comments are posted at the following ARB website: <http://www.arb.ca.gov/fuels/lcfs/lcfscomm.htm>.

²² All written comments received during the 45-day review period are posted at the following ARB website: <http://www.arb.ca.gov/regact/2009/lcfs09/lcfs09.htm>.

A commenter above contends that one has to pay a sum of \$9,000 to Purdue University in order to gain access to the model. “And even if one musters the financial resources to access the GTAP model data, he or she still would not know what assumptions had been changed by ARB staff and contractors because that information has not been made available to the public.” ARB has made available to stakeholders a GTAP model which has been installed on an ARB laptop computer in Sacramento. Stakeholders are welcome to run the GTAP model available at ARB at no cost to reproduce the ARB analysis. Stakeholders can also purchase the database from Purdue, if they elect to do so. As shown on the GTAP website, the cost to purchase the database is much less than \$9,000. Finally, as mentioned earlier, ARB shared all the assumptions and results with the public and received feedback; therefore the final results reflected those communications.

The Board acknowledged in Resolution 09-31 that estimating indirect impacts using currently available techniques is challenging. The Board found that the LCFS regulation it approved was developed using the best available economic and scientific information. In the Resolution 09-31, the Board also directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations. The Board has also directed staff to perform a comprehensive evaluation of the LCFS program in 2011 and 2014.

ARB Should Proceed More Slowly

L-83. Comment: ARB is acting hastily and rashly by including land use change emissions in the carbon intensity for biofuels. ARB should follow the lead of the European Union and delay inclusion of land use change emissions pending a more thorough review of available data and alternative estimation methods. (ICM1, ABCINC, UCD2, CO2STAR, NOVOZYM1, AGBC)

Comment: The decision to impose an iLUC handicap on agricultural biofuels was premature and occurred without sufficient understanding of the nature of agricultural systems. This decision violates the principle of a performance standard by excluding potentially viable biofuel sources and methods. iLUC should be estimated using several methods, with a preference for direct estimation. Reliance on a single method is unwise because no model is currently able to deal with this complex issue adequately. Additional time is needed to create comparative iLUC approaches. In the interim, CARB should rely only on the best direct GHG estimates.

This disagreement may seem merely like an argument among modelers. Why is it important enough to cause a delay in the adoption or modification of a part of the LCFS? The reason is that the consequences of these new policies affecting the regulation of carbon are large. The LCFS and other carbon regulations like AB 32 now in force in California are not simply carbon regulations. They will

affect all aspects of our lives and make many things that we have come to value more costly and more difficult. They will have profound long-term economic and social consequences which cannot be accurately predicted. With such radical changes in store, we should not be in a rush. A prudent approach to policy would be incremental, characterized by an appropriate sense of humility. In times of great change and uncertainty like the present, it is more reasonable to be suspicious about the reliance on a single model for creating policy. Where serious scientific disagreement exists, as it does here, more time should be taken. Before institutionalizing bias against agricultural biofuels, additional ways of estimating indirect land use changes associated with agricultural biofuels and associated carbon accounting should be developed and compared. It is possible that the estimates of the carbon costs of biofuels using differing methods may prove to be even greater than the one proposed by CARB currently. But the state will have a level of certainty and justification more appropriate to the level of consequences stemming from the regulation.

My own biases are towards developing more crop alternatives for farmers in California with the hope of improving the agro-ecological performance of farms and their profitability. The right agricultural biofuels may do both in the appropriate locations, supported by prudent policies. Trying to determine how to achieve these goals and the effort needed to do so should not be forestalled by hasty policy making. The European community, faced with same uncertainty, has opted for the additional development of assessment methods. This would be wise for California as well. (UCD2)

Comment: For the immediate future, combustion engines will remain the backbone of the U.S. transportation sector. Among the alternative fuels studied in the Staff Report, first and advanced generation ethanol work best with current automotive technology. Thus, in the short-term, the Board should not unduly penalize first-generation ethanol. To position the State's and the nation's transportation sector for the longer term, the Board should establish methodologies that recognize the manifest life-cycle advantages of advanced biofuels. California is justifiably proud of being a national leader in promoting innovation in alternative fuels and transitioning the state's economy to a much reduced GHG footprint. California's innovative LCFS will likely be a model for other states' and the nation's efforts to reduce GHG emissions from transportation. To that end, the LCFS will establish important price signals for carbon embedded in fuels. These price signals arise from the LCFS credit and debit system under which producers of fuels will accrue tradable credits for exceeding annual carbon intensity targets and incur financial penalties for falling short of annual carbon intensity targets. Since carbon intensity values will become a form of currency, and because calculation of lifecycle GHG emissions will be of central importance in other state, federal and international climate change programs, including the federal Renewable Fuels Standard, a possible federal LCFS, and possible federal and international cap and trade (with offsets) programs, it is imperative that the Board not enshrine the Staff Report's immature

and unvalidated ILUC methodologies, "as is," in final regulations. Even by postponing for two years or so the incorporation of revised ILUC penalty calculations, the Board would not be compromising its overall objective of reducing GHG emissions. (NOVOZYM1)

Response: After considering the staff's analysis and public comments, the Board concluded that the state of the science is sufficiently advanced and reliable to adopt a regulation, and that the regulation uses the best information available. Acknowledging that land use change analysis does involve some degree of uncertainty, however, the Board directed the staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effects analysis of transportation fuels and return to the Board by January 1, 2011, with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. The Expert Workgroup is expected to evaluate not only ARB's land use change modeling using GTAP but also alternative modeling approaches as suggested by some of the commenters. Furthermore, ARB is aware that the LCFS will have important economic and social ramifications both inside California and outside California, especially if the LCFS framework is adopted by other jurisdictions. As such, ARB is committed to periodically reviewing and updating the regulation. Program reviews mandated by the Board for 2011 and 2014 will facilitate these updates.

Other Approaches to Land Use Change Estimation

L-84. Comment: We wish to propose a practical approach to dealing with Indirect Land Use Change (ILUC) that seeks to address the underlying problem in an effective way. Our proposed approach (attached) is based on a top down allocation of actual emissions associated with the land use change (LUC) attributable to commercial agriculture. This provides a proportionate response based upon the scale of the actual problem, rather than the output of a theoretical model.

We propose a three step approach based upon actual land use change data, leading to progressive definition and attribution of responsibility for LUC over time: Step 1: Estimation of LUC emissions associated with marginal changes in output of commercial agricultural crops based on a share of actual LUC emissions (using standard allocation methods). Step 2: Separation of direct and indirect emissions, such that total LUC emissions = directly attributed emissions + indirect emissions (to avoid double-counting). Step 3: Progressive attribution and acceptance of responsibility towards direct effects by each sector and producer, thus reducing the residual pool of indirect emissions. (ECONOMETRICA)

Comment: CARB should develop a multi-model approach to calculating indirect land use change that also incorporated other forms of evidence, including opportunity cost. Each economic model used has its own limitations, and there is inherent uncertainty in predicting how government infrastructure and land use

policies will respond to higher crop prices triggered by biofuels that use productive land. Relying on any one model over time would be less justified than relying on a combination. CARB should incorporate opportunity cost into its analysis of biofuels that divert productive land. Biofuel strategies motivated primarily by rural development goals might legitimately ask only whether they harmed or helped efforts to combat climate change. But strategies focused on reducing climate change itself probably need to ask whether devoting land to biofuels reduces greenhouse gas emissions more than devoting land to alternative purposes. That is particularly true because most climate mitigation strategies suggest significant reliance not just on reducing deforestation but also on increasing forests. Any energy policy that competes heavily for productive land hinders the capacity to pursue these forest strategies unlike energy strategies that do not rely on productive land. (PRINCETON)

Response: Thank you for sharing an alternate approach to estimating land use change emissions. The Board approved the use of the GTAP because it was a publicly available model that was extensively peer reviewed. In our knowledge, there was no other model that met both of those criteria, to assist the Board in calculating land use change GHG emissions resulting from expansion of biofuel production. However, acknowledging the uncertainty of land use change emissions calculations, the Board directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and other indirect effect analysis of transportation fuels and to return to the Board no later than January 1, 2011, with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. Alternative approaches to estimating land use change emissions will likely be a topic discussed by the workgroup.

Positive Effects of Agricultural Expansion

L-85. Comment: The expansion of agriculture as a result of biofuel production has many significant benefits which must be balanced against the costs. Making farming around the world more profitable and sustainable, lifting impoverished farmers out of poverty, and decreasing urbanization are all benefits of biofuels which are not recognized by the regulation. (NFA1, OCGA, UCD2, ERG1)

Response: The Board agrees that the agricultural expansion induced by increased biofuel production has led to the benefits described in this comment. Because it is a fuels policy, however, the LCFS has no jurisdiction in the agricultural policy arena. The Low Carbon Fuel Standard's mandate is narrowly focused on achieving a ten percent reduction in the carbon content of California transportation fuels by 2020.

Controlling Land Use Change Impacts

L-86. Comment: We also wish to emphasize that there should be significant capacity to produce biofuels that do not divert the productive capacity of land. Much of the Department of Energy's analysis of potential U.S. biomass focuses on wastes

and agricultural residuals, a portion of which can probably be used for energy while preserving other environmental needs. A proper concern for land use does not preclude a meaningful role for biofuels. (PRINCETON)

Response: The Board agrees with this comment. In Resolution 09-31, the Board directed staff to work with interested stakeholders to develop criteria and a list of specific biofuel feedstocks that are expected to have no or inherently negligible land use effects on carbon intensity and propose amendments, if appropriate, to the regulation resulting from this analysis by December 2009. These criteria and list of feedstocks will be included as part of a guidance document prepared by ARB to streamline the application process for a carbon intensity determination under Methods 2A and 2B. The overriding criterion that must be met before a fuel can be included on this list is that production of its feedstock must not compete with the production food. The specific criteria are expected to include the following:

- a. Fuel feedstock crops grown on abandoned farmland that is currently degraded. Crops grown in this way do not compete with food crops, but they could also prove to be environmentally beneficial. In addition to their potential to improve wildlife habitat and water quality, perennial feedstock crops could increase soil carbon sequestration.
- b. Crop residues. Although crop residues increase soil fertility, decrease erosion, and improve soil carbon stores when left on fields, some residues can be removed without compromising these benefits. The removable fraction is capable of supporting the production of significant quantities of biofuels.
- c. Sustainably harvested wood and forest residues. These include the slash that is currently left in place after timber harvesting, residues from milling and pulp production, thinnings from fire prevention operations, as well as wastes from management operations undertaken to reduce competition and hasten the growth of marketable trees. In approving the LCFS, the Board directed the Executive Officer to work with stakeholders to define the terms “biomass” and “renewable biomass.” As part of that effort, the Executive Officer is to assess the effects of incentivizing the use of forest biomass as a fuel feedstock, as well as the protections that would be necessary to ensure the sustainable and environmentally beneficial use of forest biomass. The goal of this effort would be to certify pathways for fuels produced from forest biomass, should the use of this feedstock be found to be sustainable and environmentally beneficial. In addition to this state-level effort, Congress is also considering the advisability of forest biomass as a feedstock as it debates a new energy bill. Staff’s recommendation to the Board will take into consideration the results of these and other relevant inquiries.
- d. Double and mixed cropping. Biofuel crops that can be grown and harvested between existing food cropping cycles (and which do not interfere with those cycles) meet the criterion established above. The same is true for crops that can be grown along with food crops (such as between food crop rows).
- e. Municipal, industrial, and other waste streams. Waste streams that include paper products, yard waste, construction wastes, plastics, waste oils and tallow are viable sources of feedstocks that do not entail land use change impacts.

L-87. Comment: The LCFS should be designed to foster sustainable fuel production methods which reduce land use change emissions. Land use decisions such as the use of marginal lands for biofuel production and agricultural practices that lead to increased crop and fuel yields should be recognized and encouraged. (SUSCON, NFA1, BCC1, SHELL, LEONARD, GE3, ABFA, BIO, NESTE2, SHAFFER1)

Comment: As such, the ability to propose new and modified fuel pathways that include changes to emissions associated with iLUC is critical. It was noted at the March 27th meeting by CARB staff that an expanded Method 2B could provide a process by which iLUC modifications might be considered. (PRIMAFUEL)

Response: As currently designed, the LCFS does promote sustainable fuel production methods which reduce land use change emissions. Fuel produced from feedstock which can be verifiably linked to biomass grown on previously marginal or degraded lands will be assessed separately using Methods 2A and 2B and receive a land use carbon intensity that more accurately reflects the direct use of marginal lands. ARB will also recognize industry-wide changes to agricultural practices that lead to increased crop and fuel yields. As production technologies and agricultural practices evolve over time, the fuel lifecycle assessments will be periodically updated to reflect these changes. The two mandated program reviews in 2011 and 2014 will facilitate these updates. See response to Comment L-86.

L-88. Comment: ARB should concentrate on adopting appropriate sustainability criteria. A strong international focus that addresses direct land use change will obviate the need for indirect land use change penalties. (BCC1, GE3, BIO)

Comment: The separation of attribution from management responsibility which arises from predictive modeling makes the formulation of effective LUC management strategies more difficult and may impede the development of local standards and controls. For example, if the responsibility for deforestation is attributed to remote actors then there will be less pressure on governments in areas where deforestation is occurring to control this process. (ECONOMETRICA)

Response: As part of Resolution 09-31, the Board directed staff to work with appropriate agencies, regulated parties, and stakeholders to present a workplan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation. The Board further stipulated that the workplan should include, but not be limited to, a science-based definition of sustainability; how the sustainability plan can incentivize sustainable fuels; what provisions will be reviewed for inclusion in the LCFS regulation; the framework for how sustainability provisions could be incorporated and enforced in the LCFS program; and a schedule for finalizing sustainability provisions by no later than December 2011. ARB realizes however that the implementation of a sustainability plan within the California LCFS will not obviate the

need for including land use change emissions in the carbon intensity of fuels. The Board further directed staff to coordinate efforts, to the extent feasible, with the U.S. EPA, the European Union, and other regional, national and international agencies considering the adoption and implementation of an LCFS regulation or similar programs. Only through the implementation of enforceable land use change policies on a global scale could there be reasonable assurance that undesirable land use change will not occur.

L-89. Comment: ARB should lead the effort to study the links between agriculturally derived fuels and deforestation and assess the best ways to model these links and mitigate deforestation practices. The establishment of new forest protection laws and initiatives and the more effective enforcement of existing forest protection laws and initiatives in other countries must be accounted for in the land use change modeling for crop based biofuels. Studies done so far tend to assume that patterns of future land conversion will follow past patterns, neglecting the possibility of policy initiatives to steer land development away from areas of greatest environmental impact, such as tropical rain forests. (SUSCON, ACE, PRIMA FUEL, ABFA, KLINE)

Response: The linkage between agriculturally derived fuels and deforestation is an active area of study within the scientific community. ARB will continue to review the results of these studies as they are released and decide how best to incorporate these results into the land use change modeling for the LCFS. To date, ARB has not reviewed scientific evidence, nor have stakeholders provided substantial evidence demonstrating that existing forest protection laws and initiatives are effectively preventing deforestation. In the absence of evidence to the contrary, ARB has concluded that modeling based on evidence of past land use change patterns is likely to be the best predictor of future land use change patterns.

L-90. Comment: We also need to account for creative practices, such as some of the things Neste does in South America by replacing coca fields with palm plantations. Now, you can't exactly say coca is a food. It certainly isn't fiber. And so replacing some of those land uses with fuels may not necessarily reduce your carbon content, but it certainly doesn't have any negative consequences. The draft resolution that we looked at today was some of the whereases and wherefores does head in this direction. And we're very grateful for your staff accommodating some of the concerns of Neste Oil in this regard. But we would like to see a little bit more specific language. (NESTE2)

Comment: It is also important to understand that there are large amounts of agricultural land in Northeast Brazil that are suitable for sugarcane production and outside of the Legal Amazon and that utilization of agricultural land in this region is very low due to undercapitalization and infrastructure issues. As these issues are solved, it is likely to have very large growth of production for export of biofuels. Our sister non-profit organization, Sustainable BioBrazil, has been discussing with the State of Maranhao a plan for biofuels development involving

sugarcane and dual development of alcohol plants and 2nd generation biofuel plants. We have attached a letter from the Secretary of Agriculture offering to Sustainable BioBrazil 2.8 million hectares of state agricultural land for development of biofuel feedstock. This land currently remains idle with the exception of small amounts of subsistence agriculture and has historically been used for agriculture prior to 1990. While this letter of intent is contingent to approval by the new Secretary of Agriculture due to a recent change of Governor the 18th of April, it indicates large amounts of land available that has a history of agricultural use and now remains idle. If just 1 million hectares of this land were planted in sugarcane it could produce 73 million tons of sugarcane, which could be converted to 11 million tons of alcohol and another 16 million tons of 2nd generation biofuels or about 5 billion gallons of fuel. This is almost equal to the current production of ethanol in Brazil and greater than the current production of biofuels in Europe. This could be done in a way where land use change impacts were minimized from utilization of all biomass for fertilizer and biomass that would be substituted for imported coal now used in aluminum production. A detailed conversion plan and steps that are being proposed are being developed by Sustainable BioBrazil with information about the program on their web site at www.sustainablebiobrazil.com. (CO2STAR)

L-91. Comment: Countries like Brazil may also be able to adopt strategies to avoid indirect land use change. A proper concern for land use does not preclude a meaningful role for biofuels. (PRINCETON)

Response: ARB acknowledges that prior history of land used for biofuel feedstock production can affect the estimated land use change emissions. See response to Comment L-86. For example, fuel produced from feedstock which can be verifiably linked to biomass grown on previously marginal or degraded lands will be assessed separately using Method 2 and receive a land use carbon intensity that more accurately reflects the direct use of marginal lands. In addition to the use of marginal or degraded land for feedstock production, there may be other situations that justify the assessment of a separate land use change carbon intensity value. ARB will consider evidence provided by stakeholders to justify a separate land use change carbon intensity determination under the Method 2A and 2B processes.

L-92. Comment: That is POET's view of the ethanol industry's future. The starch ethanol plants located in the Corn Belt today will one day be integrated starch and cellulosic ethanol plants powered by alternative energy. There are enough available corn cobs to supply an additional 5 billion gallons of cellulosic ethanol to our fuel supply. Because we will be using the same farmers, production facilities and infrastructure, no new acres will be required to produce the additional ethanol. (POET1)

Response: In Resolution 09-31, the Board directed staff to work with interested stakeholders to develop criteria and a list of specific biofuel feedstocks that are expected to have no or inherently negligible land use effects on carbon intensity and

propose amendments, if appropriate, to the regulation resulting from this analysis by December 2009. These criteria and list of feedstocks will be included as part of a guidance document prepared by ARB to streamline the application process for a carbon intensity determination under Methods 2A or 2B. Although this guidance document does not specifically mention cellulosic ethanol derived from corn cobs, ARB will evaluate a Method 2A or 2B application against these criteria when assessing a land use change carbon intensity value to be assigned to the cellulosic portion of the fuel production. See response to Comment L-86.

L-93. Comment: Another challenge in quantifying the GHG effects of biofuels is that it needs to only consider land-use changes actually related to increased biofuels production. It would be neither fair nor accurate to attribute all current and future land clearing to biofuels, considering the increases in world demand for crops for other purposes. (ACE)

Response: The GTAP modeling does isolate the land use changes which result from increased biofuels production. The modeling does not attribute all current and future land clearing to biofuels.

Land Use Change Impacts are Greater Than Zero

L-94. Comment: Even though we can't yet estimate indirect land use change effects with great precision, we know they are non-zero, and that they must be included in the regulation. The uncertainties are generally with respect to the magnitude, rather than the direction of the effects due to iLUC. A commenter said that some corn ethanol companies, and some others in the fuels industry, are working hard to weaken the standard. Another commenter stresses that early arguments from biofuels advocates relied heavily on the uncertainty and complexity of indirect land use change as a basis for saying that it should not be included as part of the regulatory framework for biofuels (Kline, & Dale 2008). This is an argument based on obfuscation, and not a legitimate basis for ignoring land use change effects. Other commenters recognize that the science and modeling around indirect land use emissions are new and evolving; but this does not provide justification, as critics contend, to wholly ignore this central issue. It is generally agreed that the rapid expansion in U.S. corn based ethanol use beginning in 2006 has had an impact on crop prices and crop land use patterns in the U.S. Therefore, a full accounting of the lifecycle of biofuel productions is required. The GHG emission effects of pulling any acreage out of grasslands or forest lands into cultivation is clearly one factor that should be included as the indirect land use change factor. Some commenter said that the indirect land use provides very clear direction to industry. It says that avoiding the use of land is going to be rewarded. It rewards maximum efficiency and places more attention on avoiding any future conflicts with food that would come from a competition for land. Finally a commenter says that the peer-review process has found, in all 4 cases, that inclusion of indirect land-use change is based on sound science and it should be included and not discarded because of uncertainty. (EDF2, NRDC3,

NRDC5, DSOUZA, FOTE2), CAPOZ, CHEVRON2, CONOCO, TESORO1, MADEP, EE2, BIO, ENE, NRDC5, CEERT2, SIERRACLB2, EDF1, PRIMAFUEL, UIUC1)

Response: The Board acknowledged in Resolution 09-31 that the available methods for estimating indirect impacts (including land use change) are relatively new. As they continue to undergo development, the uncertainty associated with the impact estimates from these methods will decrease. ARB did try to do a full accounting of the lifecycle of biofuels production, by including the direct and the indirect impacts estimates of land use change emissions. The models used by ARB shows that as the demand for crop based ethanol production increases, there is an upward pressure on the price, and that encourages farmers to produce more of that crop, affecting the land use patterns. The Board has directed the Executive Officer to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate.

L-95. Comment: The science is clear on the basics: increased demand for crops to make fuel results in higher global commodity prices that can induce farmers in other countries to plow up sensitive ecosystems - including rain forests in South America and Southeast Asia that have a high degree of biodiversity. For some carbon-rich land types such as forests, a great deal of global warming pollution can be released from the soil and trees when this land is cleared and plowed. The scientific debate will continue on which methods and models can best calculate the emissions from such indirect land uses changes, but CARB's proposed values are, if anything, conservative. Any fuels policy that ignores the indirect consequences of biofuels production can lead to perverse outcomes that appear to decrease emissions in the U.S. fuel sector, but actually increase global warming pollution worldwide. (UCS1)

Response: The lifecycle analysis performed by ARB did include the loss of land globally for expanded biofuel production. Results such as those reported on page VI-31 of the Staff Report, include both the US and the global values for a change in the total land, forest and pasture, for increases in corn ethanol production.

L-96. Comment: We commend the ARB for its inclusion of indirect land use change (iLUC) effects in the lifecycle analyses (LCA) of fuels, and for biofuels in particular. Our understanding is that appropriate modeling in this area also demonstrates a link between policies that result in the expanded use of agricultural commodities for biofuel production and an increase in global commodity prices. This induces a further expansion of agricultural cropland into previously undisturbed habitats in order to meet the global demand for both food and fuel. The resulting loss of both the aboveground carbon and the below-ground carbon released from the previously undisturbed soil must therefore be counted as part of the life-cycle emissions associated with the production of the biofuels that induce this effect. (CVAQ)

Response: This is a reasonably accurate brief summary of the land use change process, as that process is analyzed in the ISOR. The lifecycle analysis performed by ARB did include the loss of both the above-ground carbon and the below-ground carbon released from the previously undisturbed soil for expanded biofuel production.

Dropping Land Use Change Stimulates High-Carbon Fuels

L-97. Comment: Not including the indirect land use change effects would exacerbate climate change by allowing the production and use of high-carbon fuels to continue and expand. This would be a perverse outcome, at odds with the stated goal of the regulation. If the land use costs of biofuels are left out, the benefits should be left out as well. In that event, biofuels would neither receive a charge for the direct or indirect land use change, but neither would they receive a land use credit, i.e., the credit for the carbon absorbed in plants grown on that land. Yet, without that credit, biofuels do not generate greenhouse gas benefits compared to fossil fuels. It can not be legitimate to count only benefits and not costs. Some commenters state that CARB's estimate of emissions due to indirect land use change effects may be too low. Emissions associated with changing land use patterns represent a significant source of global greenhouse gases, and domestic fuel use can significantly affect those emissions. CARB has a duty to ensure that the Low Carbon Fuel Standard maintains environmental integrity. Simply omitting indirect land use emissions within the LCFS framework would undermine, if not fully negate, the environmental integrity of the rule by potentially promoting large GHG emission increases without also requiring some compensating reductions. It is crucial that the LCFS be implemented in a way that achieves the net GHG emissions reductions intended and as necessary to help the state meet the climate protection goals of AB32. (CEERT2, EDF1, SALVARYN, IUS1, SALAZAR, CBE3, UCS2, NESCAUM2, LEEUK, UCD2, EDF4, ALA4, CE4, NRDC6, NRDC4, UCD3, ALA5, NRDC3, ATA, ENE, SIERRACLB3, CHEVRON1, CHEVRON1, AIR, ALA3, VALENTE, UCS3, CPB, COF, COF, SHAW, CAPOZ, PRINCETON, CERA2, UCD1, NRDC3, RAN1)

Response: ARB staff agrees that it is necessary and appropriate to include land use change in the Regulation. The Board acknowledged in Resolution 09-31 that the available methods for estimating indirect impacts (including land use change) are relatively new. As they continue to undergo development, the uncertainty associated with the impact estimates from these methods will decrease. ARB is committed to minimizing the adverse environmental or social impacts associated with the production of all fuels participating in the LCFS. The LCFS accounts for both direct and indirect GHG emissions associated with the production of a fuel over its full lifecycle. Land use change occurring as a result of an expansion in corn ethanol production, such as that described by some commenters above, is estimated using agricultural economic modeling (GTAP) and converted to an amount of GHG emissions. These land use change emissions are added to the direct emissions associated with fuel production resulting in an overall carbon intensity for the fuel. In the specific case of corn ethanol,

land use change emissions increase the carbon intensity by approximately 50 percent thereby making corn ethanol less attractive within the LCFS market. Therefore, the LCFS framework will help to avoid adverse land use impacts by providing less incentive for production of crop-based fuels as compared to alternative fuels which do not result in land use change. The Board however recognizes that a program which focuses exclusively on GHG emissions may ultimately reward fuels that have other adverse environmental or social consequences. Therefore, the Board directed staff in Resolution 09-31 to work with interested parties and present a work plan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation. In general, sustainability provisions will further help to avoid adverse environmental and social impacts associated with fuel production by incentivizing best management practices throughout the fuel lifecycle.

Market Innovation and Second Generation Biofuels

L-98. Comment: Failure to include ILUC initially only to add it later will lead to bad investment decisions, stranded capital and possible harm to the environment. Delay in the recognition of ILUC effects would also falsely ease the compliance burden in the early years of the LCFS, reducing the incentive to develop new technologies (e.g. cellulosic biofuels). Chevron considers harmonization of the LCFS and the Federal EISA requirements to be vital, since we will have to comply with both programs simultaneously. Since EPA is statutorily required to include ILUC under EISA, ARB must also include it. (CHEVRON1)

Comment: To spur innovation in low carbon fuels, the LCFS must send an accurate signal to the growing clean energy market. Strategic investment decisions should be based upon the best available data of the carbon footprint of alternative fuels. Failure to include a major source of pollution, like indirect land use emissions, will distort the carbon market, suppress investment in truly low carbon fuels, and ultimately result in higher emissions. (UCS2)

Comment: Proponents of agrofuels claim that cellulosic and other “second generation” fuels will have a reduced carbon footprint. While these fuels are not yet commercialized, current evidence suggests they may have a worse environmental impact than fossil fuels. We know from peer-reviewed studies that every industrial agrofuel feedstock is more greenhouse gas emitting than petroleum. The lead author of one such peer-reviewed article, Joseph Fargione, has clearly stated “From a climate change perspective, current biofuels are worse than fossil fuels.” When all impacts are assessed, agrofuel production not only does not deliver reductions in greenhouse gases but actually increases global warming emissions, particularly when forests, peatlands and wetlands are converted as a direct or indirect impact of biofuels. (RAN1)

Comment: So called “next generation” advanced fuels from non-food plants and plant parts, including forest biomass, will not resolve these problems. All industrially produced biofuel crops from fresh biomass, edible or not, still require

land, soil, water, fertilizer and other finite inputs. All biofuels based upon further expansion of unsustainable, industrial agriculture policies will intensify deforestation, toxic pollution, land conflicts with local peoples and dependence upon fossil fuel based fertilizers worldwide. It is clear that industrial biofuels are not "renewable energy" given that soils, water, land and fertilizers are all in limited supply. (SHAW)

Response: The California LCFS does not affect the volumes of corn ethanol, biodiesel, cellulosic and other advanced biofuels mandated under the federal Renewable Fuels Standard. The Renewable Fuel Standard volume mandates guarantee market security for these biofuels. The California LCFS only provides additional incentive to produce low-carbon biofuels.

It is also important to note that some biofuels will have little or no indirect land use change increment added to their carbon intensity values. The biofuel feedstocks that will be most affected by the indirect land use change increment are those fuels made from feedstocks that displace food, livestock feed, or fiber crops. Many cellulosic feedstocks displace little or no food, feed, or fiber crops. In response to Board directives found in Resolution 09-31, staff is currently preparing a table containing fuels and feedstocks expected to have little or no land use change impacts. This table will be included in a document entitled, "Establishing New Fuel Pathways Under the Low Carbon Fuel Standard: Procedures and Guidelines for Regulated Parties," a draft of which is posted to http://www.arb.ca.gov/fuels/lcfs/fuels_pw_guidance.pdf. Examples of the feedstocks in this table are municipal and agricultural waste streams, cellulosic crops grown on marginal lands that could not support food, feed, or fiber crops, wastes from standard forestry practices (thinning, fire prevention, etc.), and cellulosic crops grown between existing row crops, or added to existing crop rotations. The Board wishes to clearly differentiate these feedstocks from others, like corn, soybeans, and sugarcane, which are known to displace food, feed, and fiber crops. This differentiation should clear up most or all of the uncertainty about next-generation biofuels in the investment community.

Ecosystem and Biofuels Effects

L-99. Comment: In the face of uncertainty, an appropriate response should be a cautionary approach to land-based biofuels. For example, the GTAP calculations of land use change and greenhouse gas emissions for corn ethanol are lower than those of some other models because the GTAP model runs predict that little food is replaced by land use change. To start, almost half of the diverted food is not replaced (even after first subtracting byproducts), and a significant majority of the food that is replaced is replaced by a higher rate of yield increases spurred by higher prices. There are many reasons these predictions could be wrong and the greenhouse gas emissions from a biofuel yet much larger. One study by the European Union's Joint Research Center estimated that if only a 2.5% of the vegetable oil diverted to biodiesel were replaced by palm oil plantations established in peatlands, the emissions from the peatlands alone would eliminate

any greenhouse gas benefit from replacing diesel fuel. These uncertainties and risks provide many reasons for caution. Not only are the potential increases in emissions greater than the potential savings, but there are serious risks in pursuing a strategy that may not in the end actually reduce emissions but that displace other mitigation measures whose benefits are more certain. Given these uncertainties, we support CARB's efforts, and a full review by 2011 provides the opportunity to incorporate refinements and the evolving science of land use change analysis. (PRINCETON)

Comment: Securing world food security while maintaining operable global ecosystems may be one of the biggest challenges humanity faces in this century. Intensifying current industrial agriculture practices for vast toxic biofuel monocultures will lead to ecological disaster. Please heed the overwhelming evidence that agrofuels worsen climate change through further deforestation and the destruction of other ecosystems, drive food prices up, force more and more people worldwide into hunger and malnutrition, and decimate biodiversity and ecosystems. (LEEUK)

Comment: Corn ethanol receives billions in subsidies despite conclusive science indicating its inefficient production provides little or no additional energy other than what is used for its production, and its ecological destructiveness in terms of land, water and climate. Indeed, US agrofuel policies are already a major cause of Amazon deforestation, as US farmers switching from soya to corn is boosting soya expansion in Brazil and other South American countries. (LEEUK)

Comment: I am concerned with America and California's growing ethanol industry, and the implications it has in setting a precedent for massive agricultural industrialization of the world's remaining rainforests and other natural wildlands. We concur with the growing ecological consensus that large-scale industrial production of transport fuels and other energy from plants such as corn, sugarcane, oil palm, soya, trees, grasses, or so-called agricultural and woodland waste; threatens forests, biodiversity, food sovereignty, community based land rights and will worsen climate change. Earth simply cannot produce the vast quantities of biomass necessary to prolong our unsustainable lifestyles. Continuing to intensify industrial agriculture through increased agrofuel and biomass energy will doom humans, who are no longer integrated with ecosystems, to extinction by exhausting stocks of minerals, soils and clean water. By mining global ecosystems for biomass, the time scale of human extinction is shrinking with every crop harvest. (LEEUK)

Comment: Land Use impacts of ethanol fuel are vast and underestimated in LCFS. Numerous studies now find that biofuels, especially corn ethanol, will cause increased greenhouse gas emissions when Land Use impacts are included. An article out of Princeton and other institutions published in Science Magazine (February 2008) found that corn ethanol will double GHG emissions,

and also found that other biofuels will also increase GHG emissions by 50%: Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land-Use Change (This comment was footnoted). Most prior studies have found that substituting biofuels for gasoline will reduce greenhouse gases because biofuels sequester carbon through the growth of the feedstock. These analyses have failed to count the carbon emissions that occur as farmers worldwide respond to higher prices and convert forest and grassland to new cropland to replace the grain (or cropland) diverted to biofuels. By using a worldwide agricultural model to estimate emissions from land-use change, we found that corn-based ethanol, instead of producing a 20% savings, nearly doubles greenhouse emissions over 30 years and increases greenhouse gases for 167 years. Biofuels from switchgrass, if grown on U.S. corn lands, increase emissions by 50%. This result raises concerns about large biofuel mandates and highlights the value of using waste products. Land use change has already occurred due to inclusion of ethanol in gasoline. The drastic increase in corn produced in the U.S. for use in ethanol has already changed land patterns, to the point of stressing existing land use. Further increases will cause even greater harm. (CBE3)

Response: The Board stated in the Resolution 09-31 that as more scientific evidence on land use change become available, at its discretion, it can include such results into the Regulation. The Board concluded that, based on the current scientific understanding, the emissions associated with the indirect land use changes were substantial for biofuels and that it was necessary to include these effects in the regulation in order to accurately represent the true global warming potential of biofuels. The Board is concerned with the effect of biofuels on land, water and other resources. This is one reason that the Board has directed the staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, and to address sustainability of fuels.

L-100. Comment: The commenter submitted a list of 18 studies (p. 12-14) in support of their concerns regarding the ARB's lifecycle analysis to ensure that staff has included all the carbon intensity factors in the lifecycle analysis. (CERA2)

Response: In approving the regulation, the Board found in Resolution 09-31 that staff analysis was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective GHG emission reductions. Furthermore, the Board has directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate.

Land Use Change and Cattle Production

L-101.Comment: Perhaps the largest indirect emissions savings from biofuel production is reduced livestock numbers due to higher feed prices. Livestock have an immense GHG footprint, accounting for nearly 80 percent of agricultural emissions and ~18 percent of global anthropogenic GHG emissions (7.1 PgCO₂e yr⁻¹) – more than the entire global transportation system. (UNE2)

Comment: As another example of a factor that should be considered, the EPA in their evaluation included reductions in cattle production and subsequent reduction in emissions which ARB has chosen not to include in their scope. Given the critical nature of ILUC to the LCFS, we would recommend ARB perform the most thorough analysis possible. (WSPA1)

Response: The GTAP modeling partially accounts for the GHG emissions effect of reduced livestock numbers resulting from higher feed prices. Specifically, GTAP accounts for the reduction in cropland used to produce livestock feed grains but does not account for the reduction in enteric fermentation. The Board has directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. The effect of expanded biofuel production on livestock production and associated GHG emissions will likely be a topic for the workgroup.

L-102.Comment: The second error I see in the analysis is in the accounting of GHG emissions from the conversion of cattle pasture to agriculture (corn) land. Most cattle pasture in the US is grass land. The cattle eat the grass and convert it to methane which is 23 times more potent than CO₂. As corn becomes more expensive, feed become more expensive so meat production becomes less economical. It is logical that meat growers will then lease their land to corn growers. As I see the reality of corn expansion, brand new barren land is the last resort. The growers will first grow more corn on the land they already cultivate, then they will use land that was cultivated in the past but is now idle (because it was not profitable to cultivate). Then they would use cattle pasture that is more productive than barren land. As I said, the calculation of land use change from cattle pasture to corn is incorrect because it does not take into account the root system (corn has a much more robust root system which captures more CO₂ than a grass root system. Corn harvesting does not involve removing the roots from the ground) and it only focuses on CO₂ which misses the potent GH effect of methane gas. Add to this the GHG emission of meat processing, packaging, freezing and transportation and you will get huge savings in GHG emissions when converting cattle pasture to biofuels crop. (LUFT)

Response: With respect to the portion of the comment concerning reduced emissions associated with enteric fermentation and meat processing, see the response to Comment L-101.

Research studies show a loss in soil carbon following the conversion of pasture to cropland. In a meta analysis of data presented in 74 publications on soil carbon

changes following land use change, Guo and Gifford²³ report that conversion of pasture to cropland results in the loss of 59 percent of soil carbon. The LCFS conservatively assumes only 25 percent loss in soil carbon following land conversion of grassland or forest to cropland and therefore likely underestimates the loss of soil carbon in the conversion of pasture to corn.

The GTAP only distinguishes three types of land: cropland, available forest land, and grassland. Although the model does not distinguish between pasture and other types of grassland, future versions of GTAP may include the Conservation Reserve Program (CRP) and cropland/pasture as separate land categories. The Board has directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. Types of land available for conversion will likely be a topic addressed by the workgroup.

L-103. Comment: Many of the lands considered for significant energy grass cultivation are in use as pasture land, and are vitally important to the hay and livestock industries. If the ARB is to remain consistent in its analysis of shifting land use, displacement of pasture land should be considered in an indirect land use test. (NCGA)

Response: ARB will account for any land use change emissions associated with the production of energy crops (e.g. miscanthus or switchgrass) for biofuel.

Direct Land Use Change Impacts

L-104. Comment: I live in central South Dakota and spent over 20 years as the state's chief wildlife biologist. I witnessed firsthand the impact on the land that the corn ethanol boom created. SD has a cumulative 10 year loss of 1,000,000 acres of grass. This loss is directly tied to the development and growth of corn based ethanol in SD. The demand for corn to convert into ethanol created a corn planting frenzy that is only be rivaled by the wheat boom of the 1970s and the homestead sod conversion that occurred in the late 1800s.

To meet the demand for corn created by the ethanol refineries farmers have converted native prairie to farm corn, removed land that had been idled by conservation programs and found loopholes in existing swamp buster regulations to drain wetlands. Annual losses of native prairie have averaged about 300,000 acres per year - much of the loss occurring in the prairie pothole region of eastern SD which provides nesting cover for numerous species of grassland dependant migratory birds. Although draining small isolated wetlands by "whole field pattern tiling" may not directly increase significant additional corn acreage the practice is profitable and in high demand because it allows farmers to move their corn planting equipment faster and more efficiently thus providing additional corn acres they can farm which means higher profits. Finally, due to the high prices

²³ L. B. Guo and R. M. Gifford (2002). "Soil Carbon Stocks and Land Use Change : A Meta Analysis." *Global Change Biology* 8: 345-360.

and demand for corn, farmers are putting less land into conservation practices and are letting enrollments in programs such as CRP (Conservation Reserve Program) expire.

The total cumulative impact that corn based ethanol is having on the land is a significant reduction in acres of native prairie, a loss of wetland acres (especially small isolated prairie pothole wetlands) and a declining interest in conservation programs. All resulting in a significant loss of habitats that are critical to hold and/or sequester carbon. If the overall environmental cost of loss of grassland and wetlands habitat and the overall reduction of habitats available for countless migratory prairie nesting birds is combined with the accelerated loss of carbon, corn based ethanol should be seen as the scam on the public that it really is. (VANDEL)

Response: ARB is committed to minimizing the adverse environmental or social impacts associated with the production of all fuels participating in the LCFS. The LCFS accounts for both direct and indirect GHG emissions associated with the production of a fuel over its full lifecycle. Land use change occurring as a result of an expansion in corn ethanol production, such as that described by the commenter, is estimated using agricultural economic modeling (GTAP) and converted to an amount of GHG emissions. These land use change emissions are added to the direct emissions associated with fuel production resulting in an overall carbon intensity for the fuel. In the specific case of corn ethanol, land use change emissions increase the carbon intensity by approximately 50 percent thereby making corn ethanol less attractive within the LCFS market. Therefore, the LCFS framework will help to avoid adverse land use impacts by providing less incentive for production of crop-based fuels as compared to alternative fuels which do not result in land use change. The Board, however, recognizes that a program which focuses exclusively on GHG emissions may ultimately reward fuels that have other adverse environmental or social consequences. Therefore, the Board directed staff in Resolution 09-31 to work with interested parties and present a work plan to the Board by December 2009 for developing sustainability provisions to be used in implementing the LCFS regulation. In general, sustainability provisions will further help to avoid adverse environmental and social impacts associated with fuel production by incentivizing best management practices throughout the fuel lifecycle.

Land Use Change: Other

L-105.Comment: The fundamental assumption of the current ILUC argument – that using an acre of land in the U.S. for fuel will require almost an acre of crop development somewhere else – produces questionable results when applied to “good” public policy initiatives. For example, under the same assumption it is possible that setting aside land for the Conservation Reserve Program (CRP) creates more carbon emissions, because it takes agricultural acreage out of domestic food and feed production, which results in agricultural cultivation of grasslands and deforestation abroad. It is possible that other land protection policies, including national parks and wilderness areas, also fail the “zero sum”

land use assumption because they take timber and agricultural land out of traditional production. By the “zero sum” standard, any land conservation policy in California or the United States exports pollution (or creates ILUC) elsewhere. (NFA1)

Response: Indirect land use change is a possible result of any action that takes land out of production. It is not an inevitable result, however. As in the case of transportation fuels, only a systematic lifecycle (or similar) analysis can reveal the likelihood that a given action will trigger land use change. If land use change is likely, however, two related questions must be answered: first, ‘is the land use change impact significant?’ and, second, ‘is the magnitude (cost) of the induced land use change greater than the magnitude of the benefit that would be gained by taking the land in question out of production?’ As this comment implies, existing project evaluation methods should possibly be expanded to include the analysis of land use change impacts. The LCFS, however, has no direct influence over the evaluation projects that do not involve the production and use of transportation fuels in California.

L-106.Comment: The net corn acreage needed for actual ethanol use from 2005-06 through 2007-08, projected ethanol use in 2008-09, and the mandated level of use from 2009-10 through 2015-16 is shown in Figure 3. The increase from 2005-06 to 2015-16 totals 14.9 million acres. In absolute terms, that is a large increase. However, the increase represents less than 0.7 percent of world crop land in 2008. The increase in U.S. corn acreage required to meet the renewable biofuels mandate from 2008 to 2015 totals only 5.6 million acres, or about 0.24 percent of the world crop land in 2008. It is our opinion that any analysis of the indirect land use impact of U.S. renewable biofuels mandates must be approximately consistent with the calculations presented here. The most important point is that the U.S. mandates for corn-based ethanol through 2015 will use a very small proportion of the world’s crop land. There is a real danger that since the acreage impacts are so minuscule that they cannot be accurately modeled in a formal manner. (UIUC1)

Response: Using the formal GTAP model, as described in Chapter IV of the ISOR (as well as in the responses to the comments in the section entitled, “Unavailability of Land Use Change Estimation Methods”—see the response to comment L-1, for example), the Board determined that an increase in ethanol production from 1.75 to 15 billion gallons per year would require the conversion of about 3.89 million hectares from non-agricultural uses to agricultural production. Of that total, 3.03 million hectares would consist of grassland, and 0.86 hectares would be comprised of forest. This amounts to around a third of a hectare for every hectare of farmland diverted to the production of corn ethanol. Although this is not a large percentage of the world’s supply of arable land, the Board’s results indicate that it is not too minuscule to be modeled in a formal manner. The importance of formally modeling this conversion rate lies in the greenhouse gas emissions produced during and after land is converted to agricultural uses. The Board estimates that, for every mega joule of corn ethanol produced, 30 grams of greenhouse gases (gases with a heating trapping capacity equivalent to CO₂) are produced. This is

a significant impact—one that the Board cannot ignore. The responses to the comments in the section entitled, “Unavailability of Land Use Change Estimation Methods” acknowledge that there is some uncertainty associated with these land use change impact estimates (see the response to comment L-1, for example). In response to that uncertainty, the Board directed staff, in Resolution 09-31, to convene an Expert Workgroup to thoroughly evaluate the estimation approach it has taken, as well as the available alternatives. We note as well that the GTAP is a highly regarded, peer-reviewed model based upon a large and comprehensive set of international economic data. It is not necessary for the results obtained from GTAP to match the results from relatively informal calculations, as this comment suggests.

L-107.Comment: If the present uncertainty results in the application of overly conservative (high) iLUC factors, then this will drive fuel suppliers to blend higher volumes of biofuel component(s) in order to meet GHG reduction targets. This is true for both gasoline substitutes such as corn ethanol, and diesel substitutes such as soy biodiesel. (SHELL, A2O4NESTE2)

Response: It is true that as the carbon intensity differential between the baseline fuel and the only available low-carbon blendstock in a two-fuel-only system decreases, more of that blendstock will be needed in order for the resulting fuel to achieve compliance with the LCFS. This would be a somewhat perverse outcome, since the regulatory goal of the LCFS is to *reduce* the State’s reliance on higher-carbon fuels and blendstocks. As the carbon intensity of a blendstock increases, reliance on that blendstock should decrease. Despite this outcome, however, the overall carbon intensity of the fuels used in the state would decline—even in a two-fuel system. Ultimately, though, the LCFS is designed to stimulate a *multiple* fuel environment—one in which alternatives to most high-carbon fuels and blendstocks are available. This would tend to moderate the undesirable effects just described. The two-fuel outcome nonetheless underscores the importance of reducing the uncertainty levels associated with the carbon intensity values assigned to regulated fuels—including the land use change increment included in those values. In recognition of that importance, the Board directed staff, in Resolution 09-31, to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate.

L-108.Comment: As CARB staff has repeatedly pointed out, there are many feedstocks with zero indirect land use impacts. We believe the industry would benefit from an early CARB signal and commitment to treat such feedstocks as zero for ILUC. This can be done by adopting a list of feedstocks that have zero or near-zero ILUC that includes but is not limited to those biofuels that:

- 1) Derive from municipal or agricultural waste. 2) Do not require arable land.
- 3) Derive from crops grown on marginal agricultural lands or otherwise fallow farmlands, such as rotational and/or cover crops that are grown contra-seasonally to the primary crop. (EE1)

Response: Staff has released a draft version of the table requested by this commenter. It is included in a document entitled, “Establishing New Fuel Pathways under the California Low Carbon Fuels Standard: Procedures and Guidelines for Regulated Parties” (http://www.arb.ca.gov/fuels/lcfs/fuels_pw_guidance.pdf). This document is being prepared in response to Board directives contained in Resolution 09-31. A final draft of this document is expected to be available in December 2009.

L-109. Comment: Page IV-19 of the “Proposed Regulation to Implement the Low Carbon Fuel Standard” states: “A sufficiently large increase in biofuels demand in the U.S. will cause non-agricultural land to be converted to crop land both in the U.S. and in countries with agricultural trade relations with the U.S. Models used to estimate land use change impacts must, therefore, be international in scope.” We disagree with the above statement and believe that a thorough regional analysis of direct and indirect land use change is superior to the employment of models that are international in scope. (UIC1)

Response: Empirical evidence used in the development of the GTAP (and other computable general equilibrium models) demonstrate that, if a country reduces its exports of a given commodity, and that reduction is not accompanied by a corresponding decrease in the demand for that commodity on the parts of that nation’s trading partners, those trading partners will take steps to replace the commodity they are no longer able to import. They will attempt to increase their purchases from other exporters, or supplement supplies with substitute product (if any exist). The increased international demand for the commodity in short supply (and its substitutes) will incentivize farmers to increase their production of those commodities. If farmers are unable to meet this increased demand by simply intensifying production on existing farmland, they will plant on newly converted grasslands, forests, pastures, and other suitable cover types. Because increased ethanol production will reduce American corn exports, the land use change impacts of that production increase will spread, through our trading partners to other nations (comments disputing that increased ethanol production leads to land use change are responded to in the section entitled “Unavailability of Land Use Change Estimation Methods”). A purely regional model will not pick up these international impacts, and will, thereby, underestimate the full land use changes impacts of increased ethanol production.

L-110. Comment: On May 10th, 2007, at the National Corn to Ethanol Research Center at SIU-Edwardsville, Alex Farrell met with the Illinois Corn Growers Association and members of the Illinois ethanol industry to discuss the biofuel implications of the proposed Low Carbon Fuel Standard. This presentation was based on Dr. Farrell’s vision and work supported by Argonne National Laboratory, University of California-Berkeley, and University of California-Davis. His numbers showed that Midwestern corn ethanol (including both coal and natural gas fired ethanol plants) would reduce greenhouse gas emissions 18 percent compared to gasoline. Natural gas powered ethanol plants, in isolation, realized about a 33 percent reduction. These numbers were based on

2001 agriculture input data and older ethanol production technologies and are thus conservative relative to current corn and ethanol production technologies. (ILCORN)

Response: At the time the National Corn-to-Ethanol Research Center meeting took place, influential research results concerning the land use change impacts of crop-based biofuels had not yet made it into print. Based on the direct lifecycle emissions studies available at the time, biofuels such as corn ethanol appeared to be very promising low-carbon alternatives to petroleum-based fuels. The initial publication calling those conclusions into question—Timothy Searchinger’s “Use of U.S. Croplands for Biofuels Increases Greenhouse Gases through Emissions from Land-Use Change”—didn’t appear in *Science* until February 29, 2008²⁴. Following the publication of this and other studies of the land use change phenomenon, a serious re-evaluation of the lifecycle carbon intensities of crop-based biofuels began. Dr. Farrell and others urged the ARB to carefully consider the possible land use change impacts of the fuels that would be regulated under the LCFS. The results of the Board’s inquiry appear in Chapter IV of the LCFS ISOR (see, also, the responses to the comments in the section entitled, “Unavailability of Land Use Change Estimation Methods”).

L-111.Comment: The Staff Report states that an increase in the demand for biofuel feedstocks contributes to an increase in prices and a decrease in supply. However, there is no discussion of these market forces supplying an incentive for increased ingenuity, new techniques, or increased efficiency and production. (NCGA)

Response: The relationship between higher prices and increased efficiency and production is discussed in Chapter IV of the ISOR. This discussion is found in Section C,1, b “Key Inputs to GTAP” on page IV-20. One of the model inputs discussed in this section is the “crop yield elasticity.” This factor defines the extent to which crop yields change in response to the prices farmers receive for their crops. As prices rise, farmers will increase their investment in the more lucrative crops: they will increase fertilizer and pesticide applications; they will irrigate and cultivate more frequently; they will increase the number of plantings per rotation cycle and reduce or eliminate fallow periods; and they will implement any other measures that are known to increase yields. These are the measures farmers are known to take in order to improve their returns in response to higher crop prices. Short-run price fluctuations do not stimulate investments in long-term improvements such as the development of new varieties, however. Long-term innovations are considered “exogenous” to the model: they are not influenced by the relatively short-term price changes being modeled. As the time period covered by the model increases, however, underlying exogenous changes can affect baseline yields (short-term, price-driven yield changes fluctuate around the long-term baseline yield). This was found to have occurred in the case of the corn ethanol production increases being modeled. In response, the modelers increased baseline yields, as described on page IV-29 of the ISOR. Additional information on the handling of crop yields in the

²⁴ Timothy Searchinger et al. “Use of U.S. Croplands for Biofuels Increases Greenhouse Gases through Emissions from Land-Use Change.” *Science* 319:1238-1240 February 29, 2008

model can be found in the responses to comments in the section entitled, “Crop Yields, Production Yields, Agricultural Intensification.”

L-112.Comment: There are several fundamental problems with the way land use surcharge is applied. Generally speaking land use intensity is highly cyclical. It corresponds mainly to a combination of demand and price for agriculture products. The third error is ignoring the fact that the same market forces that increase the demand for corn ethanol and with it increase in land use intensity, will eventually find a cheaper alternative that will reduce the demand for corn ethanol and with it reduce the land use intensity: As land become more valuable and corn more expensive, corn ethanol will become more expensive too. This will further increase the effort to invest and produce ethanol from other sources such as cellulosic ethanol and ethanol from algae/seaweed. These new and cheaper sources will undermine the demand for corn ethanol which will reduce the demand for land eventually causing the land to revert back to its original use. This demand destruction is surely within the scope of the timeframe that the land use change surcharge applies to. (LUFT)

Response: As indicated by the discussions found in Chapter IV (pp. IV-23 through IV-24) and Appendix C of the ISOR, the Board agrees that corn ethanol will have a relatively short “project horizon.” The project horizon is that period of time over which corn ethanol is likely to be utilized within the regulatory framework of the LCFS. For biofuels, the project horizon determines how long a fuel has to “pay back” the land use change emissions that it generates. For a crop-based biofuel, GHG costs and benefits accrue at very different rates through time with large up-front costs and comparatively low annual benefits. The longer the project horizon, the more time the annual benefits are given to catch up with the large up-front costs. A short project horizon (e.g. less than 20 years) favors fuels that have low up-front land use change costs while a long project horizon (e.g., greater than 50 years) deemphasizes up-front land use change emissions and favors fuels that have large annual benefits.

A short project horizon was warranted in the case of corn ethanol for a couple of reasons. First, the scientific community is warning that very significant reductions in greenhouse gas emissions are needed in the near term to diminish the potential for large and possibly irreversible damage from climate change. Achieving these reductions requires approaches which promote fuels that provide earlier benefits. Second, it is very difficult to project the mix of fuels and production methods over the next three decades, much less through the remainder of the century. The assumption that the production techniques used for fuels supplied to meet the LCFS will continue for many decades to come is very uncertain. Requiring a shorter “payback” period is far more likely to produce net benefits. For these reasons, a long (e.g. 100 year) project horizon is not appropriate.

The Board approved 30 years which allows crop-based biofuels which employ the most efficient production methods to play a role in meeting the goals of the LCFS but also promotes the transition to truly sustainable fuels that provide substantial near term as

well as long term emissions reductions. As structured, the LCFS provides strong incentive (in the form of tradable credits) to both improve the greenhouse gas performance of current biofuels as well as encourage investment in 2nd and 3rd generation fuels.

This comment also raises the issue of accounting for the reversion of land used for biofuel feedstock production back to its pre-agricultural land use status. If such reversion occurs within a reasonable time frame, the resulting renewed sequestration should be credited to the biofuels that were produced from the crops once grown on them. As discussed in the ISOR, the Board acknowledges that some reversion of land may occur after the fuel no longer receives LCFS credits. A scenario showing the sensitivity of land use change carbon intensity to the inclusion of a land reversion credit is presented in Appendix C (page-18). We concluded that land reversion is highly speculative and—if it does occur—the extent and duration are impossible to predict. Therefore, the Board took the cautionary approach of assuming that no land reversion occurs.

L-113.Comment: The ILUC estimates by Searchinger et al. are not implausible, though they are subject to many uncertainties. (UNE2)

Response: The Board acknowledged, in Resolution 09-31 that current land use change estimates—including its own and Searchinger’s²⁵—are subject to uncertainty. As the land use change impact estimates currently in the regulation are evaluated using improved data sets, and more advanced analytical tools, those estimates are more likely to increase than they are to decrease. The Board’s response to the remaining uncertainty in the current set of land use change estimates was to direct staff to form an Expert Workgroup to continue studying the land use change phenomenon, and the range of techniques by which it can be measured.

L-114.Comment: From a strictly technical standpoint, it seems rather inexplicable how some who were once vehement proponents of methanol could be equally vehement opponents of ethanol – two forms of alcohol with similar motor fuel characteristics, both well-proven as effective alternative fuels.

More recently, some members of the academic community have become influential participants in California’s ethanol debates. Of late, these participants – themselves typically internally conflicted on such issues – seem to have coalesced around a position opposed to ethanol or, at least, to ethanol from conventional starch- and sugar-based production. Indeed, the controversial methodology selected by CARB to assign additional “indirect land use emissions” to the ethanol fuel cycle has origins within this community.

²⁵ Searchinger, Timothy, et al., “Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land Use Change”, Science Magazine, February 7, 2008, pp.13-14. www.sciencemag.org/cgi/content/full/1151861/DC1

Some of these same academics are long-time vocal critics of alcohol fuels generally, while others are newer to the subject and to the state alternative fuels scene. That these same academic interests are recent beneficiaries of oil company-supported R&D programs aimed at non-alcohol biofuels may or may not have anything to do with their disaffection for alcohol fuels. Another plausible reason may simply be a determination to emphasize more fundamental transportation energy transitions – such as to electric propulsion and hydrogen fuel cells – thus viewing alcohol fuels as prolonging the reign of the internal combustion engine. (MDSA)

Response: The Board is aware of no conflicts of interest that may threaten the objectivity of the research results on which it has relied. The Board has a reputation for basing its decisions on the best available information. For the LCFS, ARB worked closely with highly respected researchers from UCD, UCB, and Purdue University. In addition the work was Peer Reviewed by four independent reviewers.

The Board has concluded that the carbon intensities of crop-based fuels must include an increment that accounts for land use change—including indirect land use change. The inclusion of this increment moves the carbon intensity of crop-based alcohol fuels closer to the carbon intensity of gasoline. This reduces the value of such fuels in reducing greenhouse gases. The release of the seminal research results on the potential land use change impacts of biofuels²⁶ led to an intensive effort on the part of the ARB to determine the extent to which such impacts are associated with the fuels to be regulated under the LCFS. That assessment revealed that crop-based biofuels do create significant land use change impacts (see the response to Comment L-110, above).

L-115.Comment: What better way to incentivize fuel providers than to better manage land and restore degraded lands than to create mitigation procedures in the LCFS regulations? Some people are already doing what is right. We need to reward, not penalize, biofuel providers that committed to responsible and sustainable production practices early.

Permanent loss of farmland due to human-induced degradation is estimated to be 5-6 million ha per year. We need to focus on incentivizing fuel providers who offer low land-use impact feedstocks or who couple their fuel production to strategies that lead to better land management globally and restoration of degraded lands.

"Our approach is very much to only use raw materials that are produced in line with the principles of sustainable development. We oppose the destruction of rainforest and anything that undermines human rights or natural biodiversity," said President & CEO Matti Lievonon, speaking at Neste Oil's Annual General

²⁶ Searchinger, Timothy, et al., "Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land Use Change", Science Magazine, February 7, 2008, pp.13-14. www.sciencemag.org/cgi/content/full/1151861/DC1

Meeting in Helsinki on March 4, 2009. If regulators want to encourage companies to take such leadership roles, regulators must be careful when setting baseline performance goals or default values so as not to damage the innovators. When a company assumes a leadership role in doing what is right, it needs to be judged against its peers and not itself. (A2O4NESTE2)

The Board should also consider adopting ILUC mitigation rules to allow producers to offset ILUC impacts, or further improve their GHG profile through verifiable investments in (i) activities that improve land use efficiency, (ii) conservation of undisturbed landscapes, (iii) research and development of fuel production efficiencies, including biorefinery energy and coproduct efficiencies, and (iv) other activities that secure direct carbon benefits in the California economy. (BIO)

Response: The LCFS is designed to reward fuel producers who improve their production processes in ways that lower fuel carbon intensity. Any producer who can demonstrate to the Board that it has improved processes so as to significantly decrease carbon intensity will be rewarded with a new fuel pathway for that fuel. Using that pathway, the producer can earn additional marketable credits under the LCFS. The regulation approved by the Board, however, awards credits only to measures that directly and demonstrably reduce fuel carbon intensity. This rules out incentives for mitigation measures and offsets which—though they may significantly reduce greenhouse gas emissions—have no direct effects on fuel carbon intensity. The Board has determined that the Governor, in issuing the Executive Order creating the LCFS, intended to narrowly focus the regulation on reducing fuel carbon intensity. Creating incentives (such as credits) for mitigation measures and offsets would not be consistent with the Governor's intent.

However, developing significantly more efficient fuel production processes can earn a fuel supplier additional credits. Once such processes are implemented, the LCFS allows the supplier to apply to the Board for a new fuel pathway, including a lower carbon intensity. Once approved, the supplier may use that lower carbon intensity when fulfilling the reporting requirements under the LCFS. Any reduction in reported fuel carbon intensity earns a fuel supplier marketable credits (for reductions that are below the annual regulatory carbon intensity ceilings for gasoline and diesel fuels and their replacements).

L-116.Comment: Flexibility and review is essential. That flexibility also needs to include grandfathering compliant facilities like the European Union did when they adopted a timetable for implementing ILUC calculations in December 2008. (A2O4NESTE2)

Response: Grandfathering fuel facilities would be inconsistent with the intent of the LCFS. If the carbon intensity of transportation fuels in California is to be reduced by ten percent by 2020, the full lifecycle carbon intensity of every regulated fuel must be estimated as accurately as possible, and all regulated fuels must be treated equally.

Allowing higher carbon fuels into the California market without any disincentive would undercut this goal. This could create a situation in which the LCFS succeeds on paper only. Accounting for the carbon intensity of grandfathered fuels could reduce or eliminate any such “success.” The Board has approved a regulation designed to achieve an actual 10 percent carbon intensity reduction—not one can be construed as in any way artificial.

L-117.Comment: Well-to-wheel GHG emissions can also vary substantially on the basis of different cultivation practices and fuels used to process biofuel. It is not possible to classify biofuel as “good” or “bad” on the basis of the feedstock they are developed from alone. (VALENTE)

Response: Fuels are not classified as either “good” or “bad” under the LCFS. Instead, the full lifecycle carbon intensity of each fuel is estimated as accurately as possible. When reporting their fuel carbon intensity under the LCFS, fuel suppliers may either use these Board-approved values, or they may apply to the Board for new pathways which better describe the production process and carbon intensities of the fuels they supply. It is this new pathway application process which provides the LCFS regulation with the flexibility it needs to accommodate the variability mentioned in this comment.

L-118.Comment: Reducing carbon emissions in transportation fuel, a subject of recent national debate, is in fact an ambitious and admirable goal for the state of California. It is also a goal fraught with danger. Unless sound, proven science is used to determine carbon emissions, the state and nation could suffer the reverse effect: a transportation system that actually increases emissions.

Comments on Searchinger paper regarding the indirect effect of crop and land use once the biofuels production increase the carbon intensity penalty assessed on the ethanol industry improperly discriminates against and burdens interstate commerce; and the environmental impacts from the regulation are inadequately evaluated. The LCA and ILUC provisions in the proposed regulation applying to the ethanol industry are not supported by substantial evidence. Gov. Code Section 11350 adopts the substantial evidence standard for review of legal challenges to ARB’s adoption or repeal of its regulations. As set forth in these comments, the calculations from the use of the CA-GREET and GTAP models for determining the direct and indirect carbon emissions emitted and or caused by ethanol production, use, and demand are not supported by substantial evidence. (GE3)

Response: The Board found that the lifecycle and land use change analyses described in the LCFS ISOR are supported by substantial evidence, as defined in the California Government Code, Section 11350. This finding is based upon the following considerations:

- a. The Board reached a specific finding that the staff appropriately included indirect land use change in its lifecycle assessment (Resolution. 09-31, page 8).

- b. The Board reached a specific finding that the carbon intensity values assigned to the various fuels, including the biofuels, are scientifically defensible (Resolution 09-31, page 8).
- c. The LCFS ISOR was subjected to a peer review process. Of the four peer reviewers, one concluded that staff's analysis of land use change was "state of the art" but subject to some improvement; another agreed with the staff's contention that the land use change impact of biofuels was greater than zero, but felt staff's estimates were uncertain and should be validated against empirical data; one did not comment except to say that staff's estimates appeared to be too low; and one offered no comment, claiming no expertise.
- d. The lifecycle analysis and land use change analyses performed on ethanol are supported by ample evidence. That evidence is discussed in detail in Chapter IV and Appendix C of the ISOR, as well as in the supporting fuel pathway documents found at <http://www.arb.ca.gov/fuels/lcfs/lcfs.htm>. The discussion of the of the lifecycle and land use change analyses performed on ethanol production were lengthy and comprehensive, comprising (relative to most other topics) a large proportion of the ISOR. All these documents are contained in the rulemaking record and were available for the legally required public review periods.
- e. Even though the rulemaking record contains substantial evidence supporting the lifecycle analysis and land use change results for ethanol, the Board recognizes that the science underlying these analyses continues to evolve and to be refined. The Board therefore directed the Executive Officer in Resolution 09-31 to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate (p. 15). The Expert Workgroup is to consider changes in agricultural yields, co-product credits, land emission factors, food price elasticity, and other factors that affect land use change estimation.
- f. Finally, the LCFS regulation provides for two mandatory program reviews by the Executive Officer in 2012 and 2015 (see section 95489). One of the specific areas to be covered by these reviews is "advancements in full, fuel-lifecycle assessments," which, by definition, includes an assessment of methodological advances in the areas of lifecycle and land use change analyses, as these techniques are applied to the production of ethanol. Thus, the lifecycle and land use change analyses performed on ethanol are not only well-supported by the rulemaking record, but the Board's directives and the LCFS regulatory text ensure that continuing developments in the science of LCA and ILUC will be considered and incorporated into the LCFS program as necessary and as scientifically warranted.

L-119.Comment: To provide certainty for investors so that the necessary investments in advanced biofuels will be made, the regulations should specifically state that CI values are to be grandfathered for the 15 to 20 year life of a project. In addition, to avoid potential disruptions in supply, the EO should be allowed to make minor general changes to CI values based on new information, but major

changes (for example a significant increase in indirect land use impacts affecting a entire category of biofuels) should require board approval and should provide an adequate lead time of at least 5 years for fuel providers to make adjustments before becoming effective. (VALERO)

If ILUC values can be revised significantly given new information or modeling processes, companies and facilities that have invested in a given technology only to have that technology or feedstock suddenly invalidated or deemed less-viable will face significant economic losses. Conversely, if the process for revising ILUC values downward is unnecessarily lengthy, certain environmentally-friendly fuels may be unable to participate fully in the California market despite new scientific evidence. Consensus needs to be reached on how often changes should be allowed, who is authorized to make those changes, whether public comment will be sought prior to a change, and how investors may be protected if ILUC values invalidate a previously valid feedstock. The Association would urge CARB to consider the following approach when adopting or revising ILUC values: 1) Upon finalizing ILUC values, commission intensive research on each value. 2) Within one year of establishing final ILUC values, review each value to assess whether it remains consistent with existing science. 3) For a new feedstock, provide a two-year warning prior to adoption of a new value and allow for public input prior to finalizing the value. 4) For new facilities, always adopt the latest value. 5) For existing facilities, always allow immediate adoption of lower ILUC values but delay adoption of higher ILUC values by 20 years for advanced feedstocks or conversion processes. (ABFA)

Comment: It is critical that CARB approach this rulemaking with the utmost care, open-mindedness, and flexibility. To deliver the maximum real GHG reductions, CARB's computation of lifecycle GHG profiles must: (1) follow consistently applied and thoroughly vetted methodology; (2) be based on contemporary and complete data; and (3) account for and encourage a range of future technology advances to ensure continued reductions in the carbon intensity of the state's fuel mix. CARB's approach fails at least partially in each of these areas.

To encourage and protect investments in technologies endorsed by the Board's analyses, facilities must be able to "lock in" the lifecycle GHG profile available at time of investment as a guarantee against future revisions in ILUC methodology that increase estimated carbon debt. Investment in even the best technologies will be severely curtailed if a facility at any time could have its lifecycle GHG profile downgraded as a result of revised methodology. To further drive investment in low carbon alternatives, facilities should be permitted to adopt lower lifecycle profiles resulting from revised methodology. (BIO)

Response: The LCFS does not contain any provisions that protect investments in fuel production technologies by locking in carbon intensity values. Carbon intensities cannot be frozen either for a set period of time after they are established, nor can new facilities

lock in a carbon intensity value to insulate investors from possible fluctuations in that value. The LCFS Fuel look-up tables (which contain all currently approved carbon intensity values) are not, however, subject either to frequent changes or to changes that do not take into consideration possible economic impacts. The look-up table is included in the LCFS regulation. As such, proposed changes to that table are subject to the full State of California regulatory process. In addition to a public hearing and comment period, this process requires the responsible entity (either the Board or the Executive Officer) to consider the economic impacts of proposed changes to look-up table values. Such regulatory changes can take up to a year to complete. Fuel providers will have an additional opportunity to provide the Board with information about the consequences of changing carbon intensity values at two LCFS program implementation reviews required under the regulation. The first review must be completed and presented to the Board by January 1, 2012, and the second by January 1, 2015.

L-120.Comment: We commend the ARB for its inclusion of indirect land use change (iLUC) effects in the lifecycle analyses (LCA) of fuels, and for biofuels in particular. Our understanding is that appropriate modeling in this area also demonstrates a link between policies that result in the expanded use of agricultural commodities for biofuel production and an increase in global commodity prices. This induces a further expansion of agricultural cropland into previously undisturbed habitats in order to meet the global demand for both food and fuel. The resulting loss of both the aboveground carbon and the below-ground carbon released from the previously undisturbed soil must therefore be counted as part of the life-cycle emissions associated with the production of the biofuels that induce this effect. (CVAQ)

Response: This is a reasonably accurate brief summary of the land use change process, as that process is analyzed in the ISOR.

L-121.Comment: It seems unlikely that significant quantities of biofuel feedstock can be produced on marginal lands; some of this land is already used for livestock grazing, thus competing with food production. (CERA2)

Response: Land inventories published by entities such as the United Nations Food and Agriculture Organization show that, worldwide, there is a large supply of marginal and degraded land. To the extent that marginal land is used for livestock, conversion of that land to biofuel crops would displace livestock operations. Although reducing livestock herds does entail positive greenhouse gas impacts by reducing enteric digestion emissions and emissions from the production of livestock feed, its food supply and land use change impacts would need to be analyzed.

L-122.Comment: Corn ethanol receives billions in subsidies despite conclusive science indicating its inefficient production provides little or no additional energy other than what is used for its production, and its ecological destructiveness in terms of land, water and climate. Indeed, US agrofuel policies are already a major cause

of Amazon deforestation, as US farmers switching from soya to corn is boosting soya expansion in Brazil and other South American countries. (SHAW)

Response: This comment places the corn ethanol land use change issue into a context that includes the issues of subsidies to the corn ethanol industry, relative fuel energy balances, environmental impacts, and sustainability. Most of these issues have been dealt with in the ISOR and FSOR documents. The LCFS does not deal directly with fuel energy balances, since its focus is on the carbon intensity associated with input energy (the energy used in the production process). Theoretically, a fuel with an unfavorable energy balance could qualify for credits under the LCFS, so long as its total carbon intensity is sufficiently below that of the applicable reference fuel (gasoline or diesel fuel). The issue of the subsidies ethanol producers receive is covered in Chapter VIII of the ISOR ("Economic Impacts"). Sustainability and environmental impacts are covered in Chapter VII ("Environmental Impacts"). In response to the issues raised in the ISOR, the Board directed staff, In Resolution 09-31, to develop sustainability standards which regulated fuels must meet. The issue of land use change is covered in Chapter IV of the ISOR, and in the responses to over 600 of the comments in this document. Of the issues raised in this comment, therefore, all except fuel energy balances are being dealt with systematically and comprehensively under the LCFS.

L-123.Comment: On the Federal level we have seen the Renewable Fuels Standard impacted by the lack of commercial installations for cellulosic and other second generation biofuel production. For the LCFS, the adoption of specific indirect land use for advanced biodiesel implies that advanced biodiesel technologies are closer to commercial feasibility than most industry experts currently anticipate. We are concerned that the proposed regulations, which include setting an ILUC benchmark and substantial volume assumptions for advanced biodiesel, may put the regulations far ahead of the commercial realities. (COMF1)

Response: Clearly, the amount of time needed to develop and bring to market new fuels such as advanced biodiesel is impossible to predict. The marketable credits that fuels such as advanced biodiesel will earn under the LCFS will incentivize the development of those fuels. The availability of alternative fuels is one of the issues to be addressed during the mandated 2011 and 2014 program reviews which the regulation (at section 95489) requires Executive Officer to hold. Compliance problems created by fuel availability issues (should they arise) will be dealt with in these program reviews.

L-124.Comment: There should be significant capacity to produce biofuels that do not divert the productive capacity of land. Much of the Department of Energy's analysis of potential U.S. biomass focuses on wastes and agricultural residuals, a portion of which can probably be used for energy while preserving other environmental needs. (PRINCETON)

Response: The research on which the Board has based the volume estimates in its compliance scenarios (ISOR, Chapter VI) also indicates that significant volumes of

low-carbon fuel can be produced from the feedstocks cited in this comment (municipal and agricultural waste streams). Fuels from these feedstocks need to go through Method 2B as appropriate. Board has directed staff to address other issues, such as Renewable Biomass and Sustainability to address other potential impacts. The sustainability criteria to be drawn up in response to the Board directives in Resolution 09-31 will address the issue of whether agricultural wastes can be removed for use as fuel feedstocks without compromising environmental qualities.

L-125.Comment: For any fuel, CARB should consider establishing a minimum threshold of greenhouse gas savings. That is true if only because it ultimately will not help to pursue biofuels that generate only modest reductions in greenhouse gases as part of a strategy for reducing greenhouse gas emissions by 80 percent. These concerns, along with concerns of the other environmental adverse consequences of biofuels and the financial cost, have led to federal legislation and legislation by the European Union that also sets a minimum requirement for 45 percent to 60 percent reductions in greenhouse gases for future biofuels. Even while CARB, pursues a graded quantitative approach, it could still reasonably establish thresholds that demand at least a high level of greenhouse gas emissions before a biofuel can qualify toward meeting requirements for carbon reductions. (PRINCETON)

Response: ARB staff evaluated a number of policy instruments as it formulated the Low Carbon Fuel Standard. It concluded that the type of instrument most likely to produce the desired greenhouse gas emission reductions is one that established performance standards, while granting fuel producers and suppliers the flexibility to meet those standards in the most efficient, least-cost manner possible. Staff noted that past efforts to more directly regulate markets away from certain fuels and toward others—programs designed to bring methanol to market, for example—were not successful. Similarly, programs that set fuel production volumetric requirements, or fuel carbon intensity thresholds (or both) can reduce the range of options available to fuel innovators. In the end, staff concluded, and the Board agreed, that the combination of performance standards and incentives (in the form of tradable credits) was more likely to produce rapid innovation than more traditional regulatory approaches.

L-126.Comment: CARB should seriously consider the additional environmental concerns associated with biofuel production that competes for land with food and biodiversity. Even if the greenhouse gas calculations were to refuse to count benefits from increased hunger, those hunger effects would still exist. Even if greenhouse gas emissions from land use change for some biofuels might not be enough to fully offset the benefits, the land use change could still be large and have significant consequences for biodiversity. The many technical reports referenced above recommend an approach that focuses only on biofuels that do not divert the productive capacity of land based on this multitude of harms and risks. This is an approach that focuses on the use of waste products, such as forest waste and municipal waste, and on the production of biofuels from marginal, and degraded land. (PRINCETON)

Response: When the Board approved the inclusion of a land use change component in the carbon intensity values of biofuels whose feedstocks displace food, animal feed, and fiber crops, the Board made it clear that fuels that do not induce land use change would generally be in a position to earn the most credits under the LCFS. This decision acted as a signal to fuel markets: credits will be awarded in California based on only the fullest, most comprehensive carbon intensity accounting possible. This signal should incentivize the development of fuels, such as those mentioned in this comment, that do not induce land use change. The Board's Sustainability policy, which is currently under development, will further address impacts. Additional greenhouse-gas-generating impacts such as the emissions from the expanded application of nitrogen fertilizers will also be considered. While it continues to assess the greenhouse gas and other environmental impacts of biofuels, the Board will continue to assess the indirect impacts of all fuels regulated under the LCFS.

L-127. Comment: Just using those plants for biofuels does not by itself take any more carbon out of the atmosphere and therefore should not qualify biofuels for a credit. The proper question is whether devoting land to grow plants for biofuels results in additional carbon taken up or withheld from the atmosphere overall, and any benefit results only from any net increase. (PRINCETON)

Response: The LCFS awards credits for reduced fuel carbon content relative to a reference fuel (either gasoline or diesel fuel). Credits are not awarded based on atmospheric carbon balance impacts. As a result, fuels that are net carbon emitters can (as this comment observes) earn credit under the LCFS. Unlike a strictly implemented carbon tax, which awards credits only to fuels that have a positive impact on the atmospheric carbon balance (i.e., fuels which remove more carbon than they emit), the LCFS is designed to incent the development of fuels which reduce carbon emissions. The Board acknowledges that fuels which produce positive atmospheric carbon balance impacts are the most desirable under any climate change policy. Of the feasible policy options for transportation fuels currently available to the State of California, the LCFS promises to produce the greatest short-term reductions in carbon emissions. Because climate stabilization is the Board's stated long-term goal, it continues to consider the full spectrum of policy options as it develops its future regulatory options.

L-128. Comment: Although moving immediately to "second generation" technologies in biofuels production such as agricultural wastes and crop residues would reduce the competition between food and fuel, and is highly preferable on that basis alone, even these fuel sources have not been proven to reduce GHG emissions. Cellulosic ethanol and other second-generation crops have problems in need of consideration as well. For example, "Even the planting and harvesting of 'sustainable' energy crops can have a negative impact if these replace primary forests, resulting in large releases of carbon from the soil and forest biomass that negate any benefits of biofuels for decades." (CERA2)

Response: The Board is committed to requiring a comprehensive lifecycle analysis on all fuels. Any fuel which induces land use change impacts will have those impacts reflected in its carbon intensity value. Cellulosic fuel crops will be treated no differently from corn, soybeans, and sugarcane in this respect. Fuel crops will not be exempted from indirect effects analysis just because they happen to be “cellulosic” or “next generation.” Only fuels which do not displace food, animal feed, and fiber crops will have carbon intensity values which do not include land use change increments.

L-129.Comment: When there are marginal differences in values between particular fuels on the Lookup Chart, we believe the ARB invites financial incentives for fraud, being flooded with opt-in values to get under the baseline, and the agency having to make a "compromise" situation, subject to competition from new fuel challengers. The proposed LCFS regulation worsens this dynamic by affording the discretion to make these "compromise" decisions in one individual, even if it is after a public review process. (CERA2)

Response: The Board’s perspective on carbon intensity calculations is straightforward: the effort to slow and reverse climate change is best served when fuel carbon intensity values are as comprehensive and accurate as possible. This process can result in fuel look-up table values that are very close to one another. The only exception to this rule is the carbon intensity substantiality requirement that applies to suppliers applying for new fuel sub-pathways under the Method 2A process. Suppliers who improve the production methods for a fuel that is already in the lookup table may apply for a new sub-pathway. If the application is approved, the new sub-pathway is added to the lookup table. Before a new sub-pathway can be approved, the fully substantiated improvement in carbon intensity must be at least five gCO₂e/MJ. This requirement doesn’t apply to Method 2B applications, however. Under Method 2B, suppliers can apply for entirely new pathways (as opposed to modified versions of existing pathways). The kinds of problems described in this comment, however (pressure from fuel suppliers to allow reporting at a marginally lower carbon intensity rate), would be most prevalent in the case of fuel ‘families’ consisting of multiple sub-pathways. Although the Board is taking steps to prevent the creation of new sub-pathways with “marginally” different carbon intensities, the lookup table may still contain some sub-pathways with similar carbon intensities. The LCFS regulation does, however, contain monitoring and enforcement provisions designed to discourage suppliers from reporting carbon intensity values that do not reflect their fuels’ actual production pathways. Monitoring and enforcement will also allow the Board to discover instances of inappropriate reporting, and to discipline those who engage in this practice.

L-130.Comment: NCGA disagrees with CARB’s assessment that a shift in corn usage to generate 15 billion gallons of ethanol will cause such a significant shift in worldwide land use that it renders ethanol nearly carbon neutral to CARBOB. (NCGA)

Response: This section of the LCFS FSOR contains responses to over 600 comments that question almost every aspect of the Board’s land use change assessment. In those

responses, the Board has carefully expanded and elaborated its case for its corn ethanol land use change impact estimate. The first group of responses in the section ("Unavailability of Land Use Change Estimation Methods") contains a more general discussion of the basis of the Board's approach to land use change impact estimation, as well as a description of the actual estimation procedure. Subsequent response groups address more specific criticisms.

L-131.Comment: The CARB staff should note as well that if the data regarding the world's major ten row crops is a meaningful proxy for what has actually happened since 2001, compared to what was modeled from GTAP 2001, then the fact is that this land use change has indeed already happened. It has been driven by crude oil price-or perhaps by the combination of all energy price increases in the context of world economic growth and the recent financial bubble-but it has happened. There is no practical point in assessing a penalty to corn ethanol or any other biofuel for the veritable "volcano" of land use change in row crops which has already happened. It is a change driven not by the (seemingly modest) RFS policy, but by the throes of the world economy under pressure of increasing energy price and financial instability. The proposed regulations should be based not on a static interpretation of past economic elasticities but on the dynamic prospective interaction of many variables. (PRX)

Comment: The land use changes that may have occurred in the past because of an increased demand for biofuels will not be affected at all by a policy that is proposed to begin in 2011. All of the costs of land use changes in the past are sunk costs and should not enter into the calculus of assigning penalties for land use change. Doing so would be akin to locking the barn door after the horse got out. (NCSU)

Response: Land use change carbon intensity values are not bound by the timing of actual land use change events. Instead, these values reflect the land use change emissions associated with an increase in the volume of fuel produced, regardless of when that increase occurs. The Board estimates that any significant increase in the volume of corn ethanol produced, for example, would result in the creation of 30 grams of CO₂-equivalent per mega joule of fuel energy. This carbon intensity increment is then added to all corn ethanol sold on the California market. The rationale for this method is that any significant level of production causes, or has caused, the diversion of land devoted to food or livestock feed crops to fuel production. This diversion sets in motion a chain of events, leading to the conversion of about a third of an acre of new land for every acre of diverted cropland. The emissions from that converted land must be included in the carbon intensity value for corn ethanol. The extent to which past land use changes can be attributed to the growth in ethanol production as opposed to other forces is discussed in the section entitled "Complexity of Land Use Change Causation."

L-132.Comment: The June 26 UC letter poses the argument that underestimating ILUC for biofuels is probably worse than overestimating ILUC since underestimating ILUC would create incentives for the overproduction of crop-

based biofuel. The obvious implication is that without ILUC penalties for biofuels, we may face a runaway, unfairly advantaged cropbased biofuels industry with potentially serious land use impacts. This position seems out of touch with the realities of the U.S. transportation fuels industry. Roughly 86% of the federal subsidies handed out to energy companies between 2005 and 2009 will go to fossil fuel companies. A recent report out of Purdue University (by an author of the GTAP model) concluded that the price of oil is primarily responsible for the increased price of grains, including corn. The increasing price of agricultural commodities has put enormous strain on the conventional biofuels industry, suspending production at dozens of plants. The initial LCFS Policy Analysis published in August 2007 recognized that the new, low-carbon transportation fuels needed in California are at a disadvantage because they “compete on a very uneven playing field: the size, organization and regulation of these industries are radically different.” It is difficult to see how enforcing even conservative indirect effects against biofuels, especially while not enforcing any indirect impacts against other fuels (as is the current LCFS trajectory), would unfairly incent crop-based biofuels. More likely, it will perpetuate the status quo, and continue California on a path toward (increasingly less sustainable) oil dependence. It is also instructive to point out, as the LCFS Policy Analysis did in August 2007, the duality of California’s climate policy: to encourage investment and improvement in current and near-term technologies, while also stimulating innovation and the development of new technologies. To this end, it is imperative that the LCFS value and devalue all fuels equitably, so as not to exacerbate an already uneven playing field for alternative fuels (NFA1).

Response: This comment argues that two factors contribute to the lack of a level fuels playing field in California: an imbalance between the federal subsidies provided to biofuels and to petroleum fuels, and the allegedly inequitable practice of augmenting only biofuel carbon intensity values with an indirect effects increment under the LCFS. The issue of federal subsidies is beyond the scope of the LCFS, which has the legal authority to evaluate fuels only on the basis of lifecycle greenhouse gas emissions. The allegation that the LCFS contributes to the lack of a level playing field, however, is incorrect. As the responses to the comments in the subsection entitled “Indirect Effects Only Assessed against Biofuels” show, staff has evaluated all regulated fuels for their potential to create indirect effects. To date, significant indirect effects have been identified for crop-based biofuels only. Although other fuels have been found to involve minor indirect effects, none of those effects has been found to be significant enough to influence an overall fuel carbon intensity rating. The Board continues to be fully committed to evaluating all fuels according to the same criteria, and using the same evaluation approach and methodology. When and if significant indirect effects are identified for fuels other than crop-based biofuels, those effects will be reflected in the carbon intensities associated with those fuels under the LCFS. Unless all fuel carbon intensities are as accurate as possible, and enable clear and unambiguous comparisons across all regulated fuels, the LCFS may not be able to achieve a fuel carbon intensity reduction of at least ten percent by 2020. The Board is fully committed to reaching that goal.

L-133.Comment: The report says the following: 1. On page IV-39, the statement is made, “A significant component of the increased demand in China and other rapidly developing countries is a sharp increase in the consumption of meat and soy products in those countries. This has created a demand for imported soybeans and corn, which are used as livestock feed. This demand has helped to increase prices and has kept US exports steady. . . .” If this statement is meant to say that “China’s demand for imported corn has increased,” then this statement is not factual.” (GE3)

Response: The statement quoted in this comment is from the ISOR. It is not intended to suggest that China’s demand for imported corn has increased. China has not been a significant importer of corn from the U.S. China has increased its imports of American soy products, however—primarily for the reason cited in the quoted passage. The passage is a general observation about the effects of rising affluence on American feed crop exports.

L-134.Comment: Staff does not account for costs or disruptions to prices of crops arising due to changes in land use, although they attempt to include the resulting changes in actual emissions. There is no attempt made by Staff to quantify the potential disruptions or demand supply imbalances resulting from changes in land use. On Page ES 15, Staff admits that “In particular, staff is concerned that our estimate of land use allocation for co-products may significantly underestimate the land use impacts of soy based biodiesel, thereby overestimating its GHG benefits. Our ongoing assessment of biodiesel from soy oil may result in a significantly different estimate of its GHG impact. When a value sufficiently robust for use in the regulation has been estimated, the value will be published for public comment and proposed for certification.” (CSBR2, CSBR4)

Response: The economic impacts of the proposed LCFS regulation are discussed in two sections of the ISOR. The impacts of the regulation on the economy of the State of California is discussed in Chapter VIII, and the general impacts of biofuels on food prices and supplies are covered in section h of Chapter IV (“Food Versus Fuel Analysis”). The Chapter VIII discussion focuses on fuel price impacts and does not consider impacts on crop prices. The Chapter IV discussion does, however, acknowledge the potential for biofuel production to contribute to food, livestock feed, and fiber crop price fluctuations. That acknowledgement includes a brief discussion of the impacts of such price fluctuations on the poor. With the exception of those engaged in subsistence agriculture, the poor must spend a relatively large proportion of their incomes on food. When food prices rise, many poor are not able to divert additional funds to food purchases. The result is increased hunger. A formal analysis of the relative contribution of biofuel production to food, feed, and fiber prices, however, is beyond the scope of the ISOR. Agricultural commodity prices are driven by a number of other factors, including oil prices. The food versus fuel discussion does make it clear, however, that the Board understands and acknowledges the full range of costs and

benefits associated with fuels produced from feedstocks which displace food, feed, and fiber crops. This acknowledgement reinforces the Board's stated intention to transition away from such fuels in favor of fuels which have little or no impact on food, feed, and fiber prices and supplies.

L-135. Comment: If the biofuels industry and California are to be ready to comply with the LCFS we need an accepted methodology to estimate ILUC values for alternative crops for which there is no GTAP data. A reasonable methodology would assume that if an acre produces more energy, it should have a lower ILUC value. Figure 3 illustrates how the ILUC values for various oil crops would compare to the preliminary value for biodiesel from soy. While these numbers are not precise, they would be 4% less for renewable diesel. Of course once an ILUC value has been determined for a crop, it should be able to be further mitigated by increasing the crop per acre yield by using advanced seed and crop management practices. (A2O4NESTE2)

Response: The Board is currently working to develop the data necessary to estimate the land use change impacts of oilseed-based fuels using the GTAP model. As those estimates are generated, they will be released for comment, possible revision (based on the comments received), and eventual inclusion in the LCFS lookup table. Parties wishing to suggest alternative estimation methods may submit those suggestions to the land use change Expert Workgroup, which is being formed in response to Board directives contained in Resolution 09-31.

L-136. Comment: CARB characterizes its ILUC analysis of corn ethanol in the ISOR as generally "fair and balanced": "Although one may argue that there is no scientific consensus as to the precise magnitude of land use change emissions and that the methodologies to estimate these emissions are still being developed, scientists generally agree that the impact is real and significant. Our analyses support this conclusion. We believe that we have conducted a fair and balanced process for determining reasonable values for land use change carbon intensity and we will continue to investigate many of the issues presented above through discussion with stakeholders and analysis of current and new scientific data." We concur that CARB has conducted a fair and balanced overall process in that it has encouraged input from stakeholders, held a number of workshops, released draft materials for comment, and so on. However, we would differentiate between holding a fair and balanced "process" and attempting to achieve a fair and balanced "result." CARB has not arrived at a fair and balanced result because it has failed to adjust its ILUC analysis to correct for the significant sources of uncertainty in its estimate. We have submitted an analysis to CARB showing that most of the sources of uncertainty cited in the ISOR are more likely to reduce the current carbon intensity estimates rather than increase them. (RFA1)

Response: Staff has carefully considered the information stakeholders submitted concerning the sources of uncertainty in LCFS land use change estimates. When that

information was found to have merit, staff revised its analysis to reflect the issues raised. Baseline corn yields were increased to reflect documented yield increase since 2001; the elasticity of crop yields with respect to area expansion was likewise increased based on information from stakeholders (this elasticity quantifies the productivity of converted lands relative to existing cropland); staff agreed to reconsider the proportion of above-ground biomass that releases its stored CO₂ to the atmosphere following a land use conversion event. All of these revisions reduced current land use change carbon intensity values. Given these adjustments, the land use change carbon intensity of corn ethanol is at a very reasonable level, pending further examination by the Expert Workgroup to be convened in response to Board directives contained in Resolution 09-31. Staff's current assessment is that there are at least as many adjustments that would raise land use change carbon intensity as there are adjustments that would reduce it. Among these are accounting for emissions from nitrogen fertilizers, relaxing the assumption that increasing food prices would increase hunger (mitigating hunger with food aid would increase the amount of land use change), adopting a time accounting method that is based on the atmospheric warming potential of a fuel, and decreasing the project and impact time horizons used to convert total land use change emissions to energy-based carbon intensity units. The adoption of an opportunity cost system that considers alternative uses of biofuel cropland could also move carbon intensities higher. If atmospheric greenhouse gas concentrations could be reduced more by converting biofuel cropland to forest or grassland than by using it to produce fuel feedstock, the effect would also be to increase carbon intensity.

L-137. Comment: If the conversion of agriculture land to the production of biofuel feedstocks has the potential to increase the price of food (commodities), then the reversion of that land has the potential to reduce food prices. This is usually thought of as being "good." However, one issue not examined by CARB is whether the reversion of this land would really lead to increased U.S. exports, which would drive down prices of commodities, lowering farm income in the ROW and thereby slowing the rate of yield growth on crops in the ROW (ROW farmers will have less income to improve yields), thereby canceling out any perceived GHG benefit, and exacerbating food and land use problems. (RFA1)

Response: Discontinuing the diversion of cropland to the production of fuel crops would, as this comment suggests, produce a new equilibrium in which the U.S. is able to meet more of (or all of) its export demand. Commodity prices would decline and land use change would slow accordingly. This comment is also correct in observing that this process would tend to reduce farm incomes in "the rest of the world," which would, in turn, reduce the extent to which farmers are able to invest in yield improving measures. Lower yields, according to this line of reasoning, would increase land use change to make up for lower productivity per acre. In reality, however, these yield declines would not create a shortfall that local farmers would have to make up. The first step in this sequence of events, recall, is increased agricultural imports from the U.S. These imports would be satisfying the demand no longer being met by local production. A return to pre-biofuel export-import levels would not, therefore, stimulate land use change, as this comment maintains.

L-138.Comment: GTAP 2001 data is no empirical test of effects of RFS. For one thing, no such policy on the scale of the 2005 or the 2007 RFS had been invoked during or before 2001. From an empirical standpoint, therefore, and as will be indicated below from current USDA data, the 2001 data used in GTAP are essentially mute on what land use effects might be triggered by such a new policy. In other words, CARB staff does not demonstrate that GTAP elasticities derived from land use changes due to annual and smaller market changes might not be completely misleading with respect to the elasticities induced by large, long-term policy changes. (PRX).

Response: This comment is correct. The 2001 GTAP economic data set contains no information whatsoever about the likely impacts of a steep rise in ethanol production, and is in no way an empirical test of anything. That data is simply a quantitative snapshot of the global economy at one point in time. The model is designed to evaluate the effects on the economy captured in that snapshot of some significant economic change—a large increase in ethanol production for example. It is important to note, however, that the model has no time dimension. The modeler introduces a disequilibrium (a “shock,” such as increased ethanol production), and the model calculates what the economy described by the underlying dataset would look like when it reaches a new equilibrium (“equilibrium” being defined as the point at which supply and demand are balanced in all affected markets). The model does not specify how much time it would take to reach a new equilibrium. As such, the modeling done to determine the carbon intensity of the land use change induced by corn ethanol production does not simulate the implementation of the Renewable Fuel Standard, which specifies annual production volumes. The GTAP only uses the 15 billion gallon production level from the Renewable Fuel Standard to induce a disequilibrium into the 2001 world economy. The result is an altered 2001 economy at a new equilibrium point, reached over an unspecified time period. This comment also questions the stability of the elasticity values used over the full range of shock sizes. We note, in response, that the LCFS land use change analysis was not performed using a static set of elasticity values. Instead, the land use change carbon intensities published by the Board are based on a series of model runs in which elasticities were varied across the full range of values they can reasonably be expected to take on.

L-139.Comment: US EPA's finding in the Texas Waiver Request that the dramatic rise in corn price during the period 2002-2008 (a doubling in the corn farm price) was not caused by the federal RFS should be taken by CARB staff as a benchmark case, questioning the validity of the CARB staff's hypothesis of serial causality leading to land use change as modeled from GTAP 2001 (PRX).

Response: The Board has considered this finding in the context of other analyses that found that the diversion of an increasing proportion of the American corn crop to ethanol production did exert some upward pressure on food prices. We are aware of no evidence indicating that ethanol production exerted a large influence relative to other factors such as energy prices, but it does not appear that ethanol's influence was

insignificant. This outcome is consistent with the basic economic expectation that, if the supply of a good decreases while the demand remains unchanged, the price of that good will rise.

L-140.Comment: The CARB board should seriously consider whether it wishes to support biofuels for greenhouse gas benefits that result from reduced food consumption. Some of the crops diverted to biofuels are replaced by by-products, and to that extent food is not diverted. But the particular GTAP model runs used by CARB to calculate indirect land use change predict that much of the food not replaced by these by-products would not be replaced at all. In fact, the runs found that if the food were replaced, corn ethanol would increase greenhouse gas emissions under any scenario. When food is not replaced - a reaction to higher prices some of the effect may be relatively unobjectionable as it might simply shift consumption patterns modestly among the wealthy. But in general, the world's wealthy can outcompete the world's poor for food, so much of the predicted effect implies more malnutrition. (PRINCETON)

Response: Although the LCFS is a performance-based fuel regulation, the Board is extremely sensitive to food price impacts of biofuels whose feedstocks displace food and livestock feed crops. One indication of this concern is the discussion in Chapter IV of the LCFS ISOR of the food price impacts of biofuels ("Food Versus Fuel Analysis," beginning on page IV-41). The Board also envisions a steadily diminishing role for crop-based biofuels in the California market, as evidenced by the compliance scenarios appearing in Chapter VI of the ISOR. It must be noted in connection with these compliance scenarios, however, that some of the biofuel consumption they contain is driven by the Federal Renewable Fuel Standard production mandates. California will be expected to consume its share of Federally mandated biofuel production.

M. COPRODUCTS AND COPRODUCT CREDITS

The pathway from feedstock to final fuel production and use involves several processes and operations. These processes have the potential to generate products besides the primary fuel of interest. These additional products are termed co-products. For a current generation ethanol plant, a co-product produced is distiller's grain solubles (DGS). The wet form of DGS termed WDGS can also be dried and is termed DDGS. These can be used as a replacement for traditional feed for livestock. A complete lifecycle analysis requires an appropriate GHG credit be provided to the pathway since the use of this co-product will displace the need to produce the displaced product. For corn ethanol, DGS could replace feed corn that is used as animal feed. The model therefore has provided a GHG credit to the pathway equivalent to producing 1 pound of feed corn for every pound of DDGS produced. Appendix C11 of the ISOR has details of co-product crediting methodologies used in the lifecycle analysis.

The comments below are related to the topic of co-product credit.

DDGS 1:1 Ratio Issue

M-1. Comment: The comments provided disagree upon the value of 1 lb of DGS replacing 1 lb of corn based on the analysis in the staff report. Attention was drawn to the Argonne National Laboratory study by Wang which indicated that use of DGS in livestock provides for a displacement ratio of 1.28 for DGS. One commenter, Shurson (others refer to this study also here) provided an analysis using his research work based on which he claims the displacement ratio for livestock should be 1.24 and not as presented by staff. The net impact of the report as claimed by commenters is that not using the enhanced displacement ratio was burdening corn ethanol by not providing a co-product of the ethanol production process with a displacement credit as reported in at least two analyses. One commenter (Peer Reviewer for staff analysis) differs from all others on this issue and indicates that the 1:1 displacement may in fact be generous and may potentially underestimate the GHG impacts from corn ethanol. Some points specifically mentioned include:

- a. ARB assumes distillers grains replaces corn on a pound-for-pound basis, not the 1.24 pounds of base livestock feed Dr. Shurson calculates. This miscalculation could reduce ARB's calculated ILUC for corn ethanol by around 50 percent.
- b. The latest research from Argonne National Laboratory shows that 1 lb of DGS from an ethanol plant replaces 1.28 lbs of base feed for beef, dairy cattle, swine, which consists of both corn and soy meal. Thus, we have raw corn going into an ethanol plant, and a higher-quality processed animal feed and ethanol coming out of the plant. ARB rejected this analysis, and chose to remain with the 1 lb of DGS replaces 1 lb of corn assumption.
- c. Staff analysis ignores current data, presents a biased view, and failed to utilize appropriate scientific justification in refuting the report of Wang et al.,

- (2008). Development of public policy using inaccurate and incomplete information will result in detrimental environmental effects in direct contrast to the goals of the CA LCFS. Given the consultation of nutritional and feed industry experts by Wang et al., (2008) the Board should accept the proposed 1:1.27 DDGS to-feed ratio rather than the 1:1 proposed by ARB staff.
- d. By adding the proportional amounts of each ingredient that is decreased or increased as a result of using DGS in the diets, while accounting for market share for each species, 1 kg or 1 lb of DGS can displace 1.244 kg or lbs of other dietary ingredients to achieve the same level of performance (or improved performance as with cattle). This displacement ratio is slightly lower, but similar to the value of 1.271 kg obtained in the Arora et al. (2008) report which had limited information on swine dietary DGS usage and expected growth performance results, and DGS usage in poultry diets was not included. In Shurson's analysis, the overall displacement ratio for corn and soybean meal was 1.229 compared to the Argonne calculation of 1.28. The reason for this slightly lower value was that the corn displacement value (0.895) was slightly lower in my analysis compared to the value (0.955) calculated in the Arora et al. (2008) report. However, the soybean meal displacement ratio was higher (0.334 vs. 0.291) value in Argonne report. This indicates that 27 percent of the corn and soybean meal displacement value is soybean meal compared to 24 percent in the Argonne report. Most of this change can be explained by the greater proportion of soybean meal displaced (and less corn) in swine and poultry diets, with the remaining contribution coming mostly from savings in phosphate supplementation.
 - e. Recent studies done by Argonne National Laboratories and the University of Minnesota, as well as an International Energy Agency report, have determined the credit to be significantly higher. The University of Minnesota study states that the CA-GREET model not only underestimates the use of DOS animal feed (a major assumption influencing the value of the displacement ratio), but inadequately identifies the sources on which its assumption relies.
 - f. Corn and DDG do not have a one-to-one production ratio. While livestock producers can use DDG as a protein supplement, it lacks the essential starts that corn provides, so livestock producers still are required to feed a ration primarily of flake corn, even if DDG is readily available.
 - g. NRDC commenter states that although the RFA has asked that ARB give a higher credit for the use of DDGS based on an Argonne National Laboratory study, ARB staff has acknowledged and reviewed the Argonne study, but has also relied on other literature on the potential suitability for DDGS as a replacement feed and believes that Argonne's limited findings on potential suitability of DDGS cannot be generalized across the entire industry. Given these concerns, ARB's decision appears to be well justified and fair. (ACE, MCGA, NCB, RFA1, UMO1, UIUC2, UMN, UIUC2, RFA1, GE3, DUPONT1, NOVOZYM1, CACA2, PEERREVIEW3, NRDC3)

Comment: I hope you recognize that ARB has failed in providing accurate information to policy makers aimed at helping the environment. ARB has completely misrepresented the utilization of DDGS in livestock feeds simply because they did not take the time to get the facts around the matter. I would ask that ARB make every attempt to rectify this information to ensure environmental sustainability. (MASCHOFFS)

Comment: Therefore, when calculating land use credits due to DGS production and consumption, the usage in the swine and poultry sectors needs to be accurately estimated. Although the Arora et al (2008) report was the most comprehensive and objective analysis of the impact of DGS displacement ratios, the results are somewhat biased because it did not provide a thorough and accurate evaluation of the impact of DGS consumption in the swine and poultry industries.

Table 1. Estimated North American DGS usage rate by species (2008).

<i>Species</i>	<i>Percent of total non-export¹</i>	<i>Metric Tonnes</i>
<i>Dairy Cattle</i>	42	9,025,800
<i>Beef Cattle</i>	38	8,166,200
<i>Swine</i>	14	3,008,600
<i>Poultry</i>	6	1,289,400
<i>Exports</i>	4	510,000 ²
<i>Total</i>	100	26,000,000 ³

1 Source: S. Markham, CHS, Inc. (personal communication).

2 Source: D. Keefe, U.S. Grains Council

3 Source: Renewable Fuels Association www.ethanolrfa.org

In addition, the calculations for displacement ratios for DGS in the Arora et al. (2008) report only accounted for the amount of corn, soybean meal and urea replaced. While this is valid for calculating displacement ratios for cattle feeds, it does not fully account for partial replacement of other common ingredients used in swine and poultry diets such as inorganic phosphate, fat, synthetic amino acids, and salt. (UMN)

Response: It is estimated that over 40 million tons of DGS will be produced with the current projections for corn ethanol production under the federal program guidelines. Given such a rapid expansion of ethanol from 2005-2013, there will be large quantities of DGS available for use in the feed market. The Board accepted that economics will likely dictate that all of the DGS produced will likely find a place in the livestock market and accordingly accounted for all DGS to be consumed by the livestock industry. However, as discussed below, at this time evidence is not conclusive on all of the benefits of DGS. Data from studies currently available have not accounted for the impact of all of the DGS resulting from 15 billion gallons of corn ethanol production. Such impacts will have to be assessed in the future to better understand the role of DGS as a replacement component in cattle, swine, poultry and other animal feed.

Studies in dairy and beef cattle are not conclusive in their assessments of improvements in cattle performance when using DGS as was presented in the ISOR analysis. The Argonne report adopts a feeding efficiency gain from results from the work published by Klopfenstein and others but does not clearly specify the quality of DGS or the type of corn based feed (high moisture corn, steam-flaked corn, etc.) that it substituted for in their analysis. Until studies are available that clearly indicate the feed components that DGS substitutes for when all of the 15B gallon derived DGS becomes available, the balanced approach considered by staff in the ISOR is appropriate.

The breakdown presented by Professor Shurson citing personal communication from Markham of CHS Inc. is not available for staff to verify independently. Irrespective of this, future breakdown of DGS use is likely to be markedly different than in vogue currently. In Professor Dooley's work cited in the ISOR (Appendix C11), he estimates the penetration of DGS use in various livestock categories for 2008 based on DGS availability. His work predicts that even at 30 million tons in 2009, both the dairy and swine industries are likely to be 100 percent saturated. The projected use is in fact based on the upper end of inclusion ratios of DGS in these categories of livestock. The one area that has the largest capacity for expansion is in the beef and feed cattle industry given that 30-40 percent inclusion ratios may be possible and the total heads of cattle in this category dominate the ruminant category. So the likelihood of the breakdown cited by Shurson is not a likely scenario (with more than 40 million tons of DGS) but likely to be at 10-15 percent for the dairy and swine categories, assuming 100 percent penetration which is also unlikely based on Professor Dooley's analysis.

Another issue is the likelihood of soybean replacement in livestock when using DGS. As mentioned above, the largest user of DGS will likely be in the beef cattle industry where soybeans are typically never used as a supplement (economic perspective). In dairy, poultry, and swine there could be some soybean replacement. But for DDGS to be used as a replacement in all likely scenarios, this can only be achieved when adequate quality assurance programs are in place to ensure consistent quality of DGS are used. Until this happens for most of the DGS from 15B gallons of corn ethanol, replacement of soybeans is not always likely to occur and soybean will continue to be the primary source of protein in livestock diets. The analysis presented in Appendix C-11 of the ISOR, 1 lb of DDGS to 1 lb of feed corn ratio is the most appropriate and balanced co-product credit at this time. In the future, when data confirming the impacts of DGS (from 15B gallons of corn ethanol) becomes available, appropriate modifications can be considered.

Two commenters (NRDC3, PEERREVIEW3) do support the analysis in the report. One commenter (PEERREVIEW3) reports that even with the availability of DGS, livestock feed will still require the need for flaked corn since DGS will not provide all the necessary nutrients required for animal feed. The other commenter (NRDC3) indicates that limited findings such as in the Argonne report may not translate to similar results across the whole industry and supports the analysis presented in the report.

Overall, there are multiple issues that will need to be evaluated when considering the use of DGS as replacement feed for livestock. Some may enhance animal performance as indicated by some respondents based on published literature or personal research studies. Others may lead to suppression of animal performance or other unintended effects due to a host of issues indicated in the staff report. The ISOR served to highlight likely challenges for the use of DGS as a replacement feed given the different inferences drawn by current research and studies and took a balanced view in addressing DGS use. The analysis accounted for all the DGS produced to be utilized by the animal feed market.

However, detailed studies that take into account price driven substitution of animal feed components by DGS are not widely available at present. This is particularly important when DGS from the production of 15 billion gallons of corn-derived ethanol will become available in the marketplace. To assess the future net impact of DGS (resulting from 15 billion gallon ethanol production) as a feed replacement, market and research studies will have to be conducted to account for various factors discussed in the ISOR such as the effects of variability in quality, transportation challenges, animal response to this supplement, price competitiveness, types of feed supplements displaced, etc. Availability of data from these studies will be considered. In approving the staff recommendation as detailed in the ISOR, the Board considered the evaluation of this issue and recognized that new data from studies in the future may allow for refinements of the current analysis. Any new information would be considered by the Expert Workgroup (directed to be established by the Board per Resolution 9-31, page 15) to be formed by staff with a report due to the Board by December 2010 and also during two mandatory program reviews to be done in 2011 and 2014.

Swine Issues

M-2. Comment: The analysis presented in Appendix C-11 is flawed since it does not include a much more exhaustive review of literature particularly those related to feeding DGS to swine. Also, it used only one reference for swine related information which was from 1993 and did not utilize information from 83 references cited by Stein and Shurson in 2009. Yet, conclusions were made about the use of DDGS in swine diets based on this limited work. Some points specifically mentioned include:

- a. Published research has documented that DDGS may be included in diets fed to growing and reproducing swine in concentrations of at least 30 percent of the diets. At this inclusion rate, no reduction in performance will be observed if diets are formulated correctly (may require fortification with crystalline Lysine to endure utilization of protein from DDGS is comparable to protein from corn-soybean meal diets).
- b. A large number of research projects have been completed to evaluate the consequences of including DDGS in diets fed to swine. A recent review by Stein and Shurson in 2009, concluded that "DDGS can be included in diets fed to growing pigs in all phases of production beginning at two to three week

post-weaning in concentrations of up to 30 percent DDGS, and lactating and gestating sows can be fed diets containing up to 30 and 50 percent DDGS, respectively, without negatively affecting pig performance". (UIUC2, UIUC2, UIUC2)

Comment: It is clear from the record that ARB staff has been selective in its use of available data to determine corn ethanol coproduct credit values. ARB staff should redo this evaluation, relying upon the most recent data available and local animal nutrition scientists at the University of California, and the California State Universities, and the CA Department of Food and Agriculture. (SHAFFER1)

Response: There is no doubt that DGS is being used as a replacement feed. There are, however, many variables which do not guarantee similar responses from all livestock fed with DGS as a replacement component as was detailed in Appendix C11 of the ISOR. There are many studies that have expressed concerns with the use of DGS as a feed substitute and have been presented in the ISOR. As for higher levels of DGS use, it will depend on price competitiveness of DGS with other feed components, and also the different stages in the growth cycle of pigs.

The commenter also stated that the ISOR presented analysis by considering limited research reports when there actually are many such literature studies available. However, detailed studies that take into account price driven substitution of animal feed components by DGS are not widely available at present. This is particularly important when DGS from the production of 15B gallons of corn-derived ethanol will become available in the marketplace. To assess the future net impact of DGS (resulting from 15B gallon ethanol production) as a feed replacement, market and research studies will have to be conducted to account for various factors discussed in the ISOR such as the effects of variability in quality, transportation challenges, animal response to this supplement, price competitiveness, types of feed supplements displaced, etc. Availability of data from these studies will be considered. In approving the staff recommendation as detailed in the ISOR, the Board considered the evaluation of this issue and recognized that new data from studies in the future may allow for refinements of the current analysis. Any new information would be considered by the Expert Workgroup (directed to be established by the Board per Resolution 9-31, page 15) to be formed by staff with a report due to the Board by December 2010, and also during two mandatory program reviews to be done in 2011 and 2014. See also response to Comment M-1.

Sulfur Enhancements in Feed from use of DDGS and Likely Complications

M-3. Comment: Commenters mainly point out that increased sulfur in diets due to inclusion of sulfur enriched (compared to corn) DDGS has not been an issue for livestock feeders. One commenter does acknowledge that there have been reported cases of polioencephalomalacia in regions with higher levels of sulfur in water and feed ingredients. Some points specifically mentioned include:

- a. A comprehensive study conducted indicates that although sulfur in DDGS varies from 0.2 to 1.0 percent, only 0.2 to 0.3 percent of sulfur in DDGS comes from amino acids in feedstock, which is beneficial to animals.
- b. Concerns about higher sulfur have not limited the use of DDGS use in cattle feeds (38 percent of production is fed to beef cattle).
- c. Challenges to DDGS use due to higher sulfur in water are regional issues and cannot limit its use across the entire industry. (UMO1, UMN, NCERC3, NRDC3)

Comment: We welcome the author's recognition of the challenges in increasing the usage of DDGS as animal feed due to factors such as "variability of nutrient" and "transportation". However, their analysis of the challenges is poorly presented, and the evidence to support their arguments has no traceability. The authors have exhibited limited knowledge of DDGS consumption by different animal types, and seem confused about nutrient digestibility by different animals. Therefore, the authors are not qualified to evaluate a comprehensive report like the "Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis", which is heavily based on animal nutrition and animal performance studies using DDGS as feed. (NCERC3)

Comment: When author's use fear mongering statements such as, "The industry faces challenges due to reports of neurological or digestive problems in animals which are likely to cause managers to be wary of including DDGS in diets", it exemplifies their disdain for the ethanol industry and lack of knowledge on the importance that DDGS is serving to the livestock industry. (NCERC1)

Comment: I am writing to express my concern with the inaccuracies regarding the assessment of the fuel ethanol co-product, Distiller's Dried Grain with Solubles (DDGS) presented in the California Air Resource Board's (ARB) proposed rule for the development of a Low ARB Fuel Standard (LCFS). (UIUC3)

Comment: We recommend the authors reinvestigate this matter to truly understand the studies and progress which have been made on the consumption of DDGS by various animal types, and then come up with a scientifically sound assessment. (NCERC1, NCERC3)

Comment: The abundance of data does not support grave consequences in level of growth performance by ruminants fed distillers grain compared to diets without distillers grain. (UMO2)

Comment: ARB staff conclude stating significant barriers exist to prevent widespread adoption of DDGS as livestock feed. Based on ARB staff analysis one would have to agree with this conclusion, however, ARB staff incorrectly interpreted and omitted key DDGS information. (UMO1)

Response: DGS typically contains three to six times the amount of sulfur compared to the corn from which it was derived. Total sulfur consumption by livestock includes sulfur from formulated feed, water, foraging, etc. Use of sulfur-enriched DGS as a replacement for other feed components is therefore likely to enrich the total sulfur intake of an animal. Increased levels of sulfur in feed has been linked to nervous system disorders such as polioencephalomalacia as indicated in Appendix C11 of the ISOR. This is likely because sulfur suppresses uptake of nutrients critical for normal functioning of the nervous system in livestock.

The enhancements of sulfur when using DGS is a factor that feed formulators will have to consider when designing their optimal feed rations. This will be more so in regions which have higher levels of sulfur (in water, crop, etc.) or when blending higher levels of DGS as replacement in animal feed. Therefore, it is not necessarily only economics or other benefits that will dictate the use of DGS but also the concerns with increased sulfur in animal diet formulations. One commenter (NRDC3) does acknowledge the reporting of brain disorders related to sulfur enrichment from the consumption of DGS.

Overall, there are multiple issues that will need to be evaluated when considering the use of DGS as replacement feed for livestock. Some may enhance animal performance as indicated by some respondents based on published literature or personal research studies. Others may lead to suppression of animal performance or other unintended effects due to a host of issues indicated in the Staff Report. The Staff Report served to highlight likely challenges for the use of DGS as a replacement feed given the different inferences drawn by current research and studies. The analysis did however acknowledge that all of the DGS produced would likely be utilized by the livestock market. Also, see response to comment M-2.

M-4. Comment: It is common knowledge among animal nutritionists that protein digestibility of DDGS is different for various animal types. The data the author's present in Table C11-1 on DDGS protein digestibility and availability is confusing and groundless. We (NCERC) have studied the furosine content in DDGS, a product of "browning reaction" and a potential in vitro indicator of lysine digestibility for swine diets (2). We learned, from DDGS samples representing 55 ethanol plants in the U.S., the average available lysine is 88 percent of total lysine. Animal feeding trials are taking place to confirm the correlation with in vivo data. (NCERC3)

Response: The table being referenced was from a published article which has been cited in the ISOR. As for correlations of furosine with 'browning' and in vitro indicator of lysine digestibility, this is for use by feed formulators to allow them to create rations for the optimal growth and performance of livestock. There is adequate literature reference that confirms variability of available lysine content, variability of the quality of DGS from temperatures used in the ethanol production processes in various facilities, etc. As for confirmation of the correlation, it would definitely be a welcome addition to the tools available to feed formulators. See also response to Comment M-1.

Steam-Flaked Corn

M-5. Comment: The report cited work which concluded that replacing steam-flaked corn with DDGS decreased rumen pH and depressed rumen fermentation. Commenters stated that using one study to make such a conclusion is unwarranted and one in fact indicates it defies logic. Two of the commenters however state in their comments that when DDGS replaces corn in diets, a benefit reported is the prevention and/or reduction of sub-acute acidosis due to decreased rumen pH. (UMO1, NFA2, UMO2).

Response: The attribution of decreased rumen pH was included to focus on one of many challenges likely to be encountered when using DGS as a replacement feed. Overall, there are multiple issues that will need to be evaluated when considering the use of DDGS as replacement feed for livestock. Some may enhance animal performance as indicated by some respondents based on published literature or personal research studies. Others may lead to suppression of animal performance or other unintended effects due to a host of issues indicated in the staff report. The ISOR served to highlight likely challenges for the use of DGS as a replacement feed given the different inferences drawn by current research and studies. The analysis did however acknowledge that all of the DGS produced would likely be utilized by the livestock market. Also, see response to comment M-2.

Phosphorus in DDGS

M-6. Comment: Staff's suggestion that use of DDGS in livestock feed will lead to enhanced phosphorus in manure which will cause a manure management issue is incorrect. Livestock such as swine and poultry are able to digest much of the DDGS-derived phosphorus compared to phosphorus from corn or soybean, thereby limiting the phosphorus excreted. Better utilization also preempts the need to add supplemental phosphate in feed lowering costs to the farmer. Some points specifically mentioned include:

- a. DDGS contains between 0.6 and 0.8 percent phosphorus compared to 0.26 in corn and 0.65 percent in soybean meal. A benefit of using DDGS in swine diets is that it reduces the excretion of phosphorus (DDGS derived) because of the greater digestibility of phosphorus in DDGS (50 to 69 percent) compared with corn/soybean meal (less than 30 percent). As a result, the inclusion of total phosphorus in the diet can be reduced when DDGS is used, which in turn will reduce the excretion of phosphorus from pigs, and thus help reduce the release of phosphorus to the external environment. This was clearly shown in a recent research project conducted at the University of Illinois, where pigs fed a corn-soybean meal diet excreted 1.68 g of phosphorus per day while pigs fed a corn-soybean meal-DDGS diet excreted only 1.43 g of phosphorus per day although the intake of phosphorus was nearly identical between the two diets.
- b. The high phosphorus levels in DDGS serve merely to displace a like amount

of phosphorus from mineral supplements. It is my experience after using DDGS for several years that the total phosphorus content of diets high in DDGS is no greater than that of typical diets without DDGS.

- c. The phosphorus content and digestibility of phosphorus from DGS is high (65 to 90 percent) for all species. This provides a significant nutritional advantage for DGS in swine and poultry diets and also allows for a significant reduction in the need for supplemental inorganic phosphate (fertilizer grade source of P) to meet the phosphorus requirement while substantially reducing diet cost. Furthermore, using DGS to displace corn and soybean meal, which have much lower phosphorus content and digestibility, can substantially reduce the amount of phosphorus excreted in manure. (MASCHOFFS, UAR, UIUC2-, UIUC2, UIUC3, UIUC2, UMN, NRDC3, NFA2).

Response: The statement by the commenters above referred to the livestock population as a whole. For a significant portion of the DGS from 15B gallons of corn ethanol production to be used (excluding export), the largest sources are expected to be cattle (with beef cattle likely capable of the highest percent replacement in feed). Use of DGS in cattle will enhance phosphorus in manure, a concern when using DGS as a supplement in livestock feed. As for use of DGS in swine, there are studies that have reported better digestibility of DGS based phosphorus which may reduce phosphorus in waste, but additional details such as the inclusion of additives such as phytases to minimize phosphorus excretion have not been provided in these studies. One commenter (NRDC3) supports the statement that use of DGS in cattle is likely to lead to manure management issues. See also response to comment M-2.

Lysine Supplement

M-7. Comment: The comments conclude that the Staff Report is incorrect in its statement that supplemental lysine must be included in cattle diets when feeding them DDGS. Some points specifically mentioned include:

- a. Microbial population in the rumen of cattle and sheep (ruminants) can ferment DDGS protein and fiber fractions into microbial protein which passes into the lower digestive tract supplying necessary amino acids such as lysine. The use of supplemental lysine is not necessary as indicated in the report.
- b. The bacteria in the rumen of cattle break down any type of protein, and if lysine is tied up in the Maillard reaction, they are able to break this link and digest the protein. Cattle are able to produce their entire range of amino acid needs from ANY type of protein and would not respond to supplemental lysine.
- c. As for swine and poultry, there are now rapid quality control tests that determine the digestibility of the amino acids in DDGS and allow the nutritionist to adjust for batches that may have reduced digestibility. (UAR, UMO1)

Response: While microbial protein that is synthesized in the rumen contains essential amino acids required by cattle, there is controversy surrounding the question of whether this is sufficient. There are several published studies where cattle have responded productively to supplemental lysine, methionine and histidine that was fed in a rumen protected form or provided by post-ruminal infusion (and many studies that have shown no benefits at all). Higher temperatures during the fermentation or drying process may lead to loss of available amino acids (lysine is typically the most damaged due to heat) and diets using DGS may require supplemental lysine particularly for dairy cattle, swine and poultry. One commenter does acknowledge that tests conducted prior to feeding to determine the amino acid profile of the DGS will allow the feed formulator to adjust other components to make up for any shortfall in DDGS based proteins. Also, see comment M-2 and M-3.

Incomplete Report/Study

M-8. Comment: Staff's assertion that an extensive review of literature was conducted is flawed since there are numerous articles published but staff reviewed only a limited number. Professor Kerley states that there are at least 88 scientific peer-reviewed articles and the ISOR only reviewed 11 related articles, of which just six were peer-reviewed. Professor Stein indicated that he has published 83 articles on swine feeding but staff used only one (also 16 years old) to derive assessment on swine feeding. In summary, we recommend the authors reinvestigate this matter to truly understand the studies and progress which have been made on the consumption of DDGS by various animal types, and then come up with a scientifically sound assessment. Some points specifically mentioned include:

- a. Globally this is the worst representation of scientific literature review. It appears that this Appendix was written with a severe bias against ethanol.
- b. The work is based on very few references (for swine only one) and at least one of the references listed in the Appendix is incorrect or falsified.
- c. There were no distiller grain experts who peer reviewed this report. The ones that have said -- and I'm just going to summarize one, because there's about 12 of them on the record. "I've no interest in the merits of ethanol use. What I believe is relevant is the truth regarding the nutritional value of distiller's grain. As the report now exists, the truth is not recorded."
- d. In the reference section, a reference from San Diego State University by Kent Tjardes and Cody Wright is listed (reference #8). This is a reference that the authors must have invented - because Kent Tjardes and Cody Wright have never published anything that was published by San Diego State University (I have checked with Dr. Wright).
- e. Extensive review constituted 24 citations from 1987 to 2009. A keyword search using corn distillers grains returned 204 and 470 citations from two journals from 1987-2004. Given the number of published studies available use of 24 citations should not be construed as an extensive review. Wang et al., (2008) was cited as using data from "a few studies" to analyze DDGS

- suitability yet they cited 27 references including communications with animal nutrition and feed industry experts.
- f. It is not made clear what “traditional feeds” are in the document in the first paragraph on page C-52 or how the LCFS model of DDGS utilization is developed. Wang et al. (2008) review is superior and this is an area that staff clearly needs to educate themselves on to be able to competently make any conclusions that direct important policies of the State of California.
 - g. All three of these experts issue scathing analyses of the overall issue.
 - i. Dr. Monty Kerley states “[t]he report reads as fiction supportive of a desired outcome but not as factual information useful for establishment of policy.”
 - ii. Dr. Hans Stein of the University of Illinois states, “[t]he Appendix is filled with factual errors that make one question all the conclusions that are reached.”
 - iii. Dr. Justin Sexten states, “The [ARB co-product analysis] ignores current data, presents a biased view, and failed to utilize appropriate scientific justification [development of public policy using inaccurate and incomplete information will result in detrimental environmental effects in direct contrast to the goals of the CA LCFS.”
 - h. There is also criticism coming from within the UC system. Glenn Nader of UC Cooperative Extension, University of California, states, “[a]nimal nutrition expertise is greatly lacking in the discussion on pages C-51 to C-54. On C-54 the document demonstrates a lack of knowledge on the livestock feeding industry and the educational institutions that work with them. (UMO2, UMO2, UIUC2, MASCHOFFS, PE2, UIUC2, NCERC3, NFA2, MASCHOFFS, NFA2, UMO1, UCANR, NFA2, UMO2)

Response: The analysis in the ISOR essentially presented many challenges that livestock farmers and feed formulators may likely face when replacing current feed components with DGS. Experiments under carefully controlled (Golden DGS, no-brown DGS, etc.) have reported beneficial performance in many studies but there are other studies that do not claim any advantages but report disbenefits when using DGS as a replacement feed. Nervous system problems such as polio encephalamalacia have been reported in some instances and excess phosphorus in animal manure is also a likely concern when using DGS. Quality of DGS and availability of nutrients from batch to batch and facility to facility also add to the variability that the feed formulator has to account for when using DGS in animal feed. Transportation logistics, shelf life of wet DGS, price competition with other feeds are also important factors in the consideration of DGS use in feed rations.

Specifically to address some of the points being raised:

- The analysis was presented as being balanced given that the full impact of 15B gallons of ethanol will not be realized until 2012 or later. There are mandatory program reviews in 2011 and 2014 at which time, this could be refined based on data available in the future.

- The reference being quoted as incorrect or falsified should have been from researchers at South Dakota State University (SDSU) but was mistakenly transposed as from San Diego State University (SDSU).
- Two experts from federal agencies reviewed the report before it was published.
- The analysis utilized a sampling of representative literature to highlight the challenges to widespread use of DGS. The analysis did however account for all DGS being used as animal feed.
- The analysis presented served to focus on various issues that need to be considered for the widespread adoption and use of DGS, produced as a by-product of the corn ethanol production process. The analysis, even with all the likely challenges did account for all of the DGS produced from 15B gallons of ethanol to be consumed either by the domestic or international livestock industry. When data relevant to the actual use of DGS in the future become available, appropriate refinements could be considered. They could be reviewed during the mandatory reviews in 2011 and 2014.

Also, see comment M-2.

GTAP and Cost Issues

M-9. Comment: I disagree with the staff recommendations on DDGS. Livestock producers will use all the DDGS if it is produced and priced correctly. In California, it could displace canola meal in most rations, which is being shipped in from Canada for approximately \$70/ton for transportation. This would greatly reduce ARBOn footprint if the DDGS was produced in California. (UCANR)

Response: The analysis presented in the ISOR accounts for all the DGS being used assuming that it will be priced cost-effectively. This implicitly assumes that DGS will compete with available feed components (including canola) to ensure a low cost optimal feed ration for livestock in California. The analysis does credit DGS its appropriate co-product credit based on the issues discussed in the ISOR. Also, see comment M-2.

M-10. Comment: Because of the greater nutritional value of DDGS than of corn, the economic value of DDGS is also greater than of corn. The exact value of DDGS depends on the cost of not only corn and soybean meal, but also on the cost of monosodium phosphate and crystalline Lysine. With current costs of monosodium phosphate at \$500 per ton and crystalline lysine at \$1.75 per kg, the value of DDGS can be calculated under different scenarios of the cost of corn and soybean meal (Table 5). It appears from this analysis that the economic value of DDGS is always between the cost of corn and the cost of soybean meal. Because corn is less expensive than soybean meal, the value of DDGS is always greater than the value of corn (on a per ton basis). Only in the unlikely event that

the cost of soybean meal is lower than the cost of corn will the cost of DDGS be lower than that of corn. Thus, the economic value of DDGS follows a pattern that is similar to the nutritional value with DDGS having a value that is in between the value of corn and soybean meal. (UIUC2)

Response: Feed value of soybean meal is higher than corn or DGS since value is placed on the protein content of soybean meal. An issue is the likelihood of soybean replacement in livestock when using DGS. As indicated in the response to Comment M-1, the largest user of DGS will likely be in the beef and cattle feed industry where soybeans are typically never used as a supplement (economic perspective). In dairy, poultry, and swine there could be some soybean replacement. But for DDGS to be used as a replacement in all likely scenarios, this can only be achieved when adequate quality assurance programs are in place to ensure consistent quality of DGS are used. Until this happens for all of the DGS from 15B gallons of corn ethanol, replacement of soybeans is not always likely to occur and soybean will continue to be the primary source of protein for livestock diets. The analysis presented in Appendix C-11 of the ISOR, 1 lb of DDGS to 1 lb of feed corn ratio is the most appropriate and balanced co-product credit at this time. As to the specific pattern of DGS pricing relative to corn, DGS prices typically are higher than corn but have also been lower. Lower prices relative to corn are most likely due to lower quality (excessive browning during fermentation which lowers the nutritive quality could be a factor) or related to excess supply of DGS (regionally). For all of the DGS produced from 15B gallons, studies need to be conducted for all regions to provide a clear picture of the pricing and actual use of DGS as a replacement feed. The mandatory program reviews in 2011 and 2014 could reassess this issue based upon available data in the future. Also, see comment M-2.

M-11. Comment: It is claimed that the price of DDGS will go up if the price of corn is increased and that “higher prices render DDGS less cost-effective as a replacement feed, particularly where soybean meal is to be replaced”. This statement is in direct contrast to the historical pattern of price relationships. Prices of soybean meal have always increased as the cost of corn went up. The cost-effectiveness of DDGS has actually increased every time the cost of corn has increased and there is no basis for suggesting that the opposite is the case. (UIUC2)

Response: The prices of soybean are not a direct function of the price of corn. Crop failures, additional demand for soybeans (e.g., for biodiesel production) are some of the market effects likely to directly impact soybean prices. In a similar manner, corn prices in 2006-07 were higher than historical prices, mostly driven by higher demand for corn brought on by higher production of corn ethanol. As to pricing of DGS, it tends to follow corn prices since it is a co-product of the corn ethanol production process. Actual prices however are dependent on quality, transport distance, dry or wet DGS, availability, etc. which can impact final delivered price of DGS. Again, as presented in the ISOR, there are many factors that impact DGS as a feed replacement. At the present time, the analysis used a balanced approach and considered a 1:1 replacement ratio for DGS compared to corn.

Historical patterns of price relationships are likely to change in the future since much higher values of DGS will become available. This is particularly important when DGS from the production of 15B gallons of corn-derived ethanol will become available in the marketplace. To assess the net impact of DGS (resulting from 15B gallon ethanol production) as a feed replacement, market and research studies will have to be conducted to account for the effects of various factors considered in the report such as variability in quality, transportation challenges, animal response to this supplement, price competitiveness, types of feed supplements displaced, etc. When data from these studies will become available it will allow for a re-evaluation of this issue. In approving the staff recommendation as detailed in the ISOR, the Board considered this issue and recognized that availability of data from future work would allow for refinements to the current analysis. The new information would be considered by the Expert Workgroup (directed to be established by the Board per Resolution 9-31, page 15) to be formed by staff with a report due to the Board by December 2010 and also during two mandatory program reviews to be done in 2011 and 2014. See also response to comments M-1 and M-10.

Gastric Ulcerations from Use of DDGS

M-12. Comment: The smaller particle sizes likely to result from the use of DDGS in animal feed will not predispose livestock particularly swine to gastric ulcers. The commenters indicate that in their studies they have not observed any such incidences of ulcerations in swine. Some points specifically mentioned include:

- a. While it is true that fine particle size of complete feeds can increase the incidence of gastric ulcers in swine, particle size of DGS often exceeds 700-800 microns and only represents a maximum of 20 to 30 percent of the diet. Particle size of corn and soybean meal has a greater effect on overall diet particle size than most sources of DGS.
- b. Smaller particle size in DDGS is claimed to predispose hogs to ulcers is an absolutely untrue postulate that is not based on any scientific work. In fact, the average particle size in DDGS is very close to that recommended for swine (approximately 650 microns) and there are no documented cases of ulcers caused by DDGS fed to pigs. (MASCHOFFS, UIUC2, UMO2, UMN)

Response: The ISOR (Appendix C11) indicates that when smaller particle sizes from the use of DDGS are used in animal feed, it could predispose pigs to ulcerations. The main objective of presenting this information was to focus attention on an additional factor (among many others cited in the ISOR) that a feed formulator would have to consider when designing optimal feed rations for livestock. Though this may not be a dominant factor, it is still a factor that may influence the formulator's decision when economically competing feeds are available. Also, see comment M-2.

DDGS Transport

M-13. Comment: The commenters refer to the inaccuracy in the analysis of transport costs of Wet DGS. While the challenges to shipping and handling WDGS (or DDGS) is considered in the report, this has not been a challenge since DGS is being widely used in the feed and export market. One commenter points to the fact that DDGS is shipped around the world. Some points specifically mentioned include:

- a. “WDGS transportation is based on as-fed basis and subsequently the cost of transportation has been discounted to accurately reflect the moisture/dry matter of the WDGS”.
- b. While it does have some handling problems in shipping, this in itself should not be a consideration to your Board, but to the feed industry. If it is not feasible to use, the industry would not be using it. (NCERC1, UAR, UMN, NRDC3)

Response: Transporting of WDGS is expensive given that more than 50 percent of it is water. Transporting costs beyond a 50 mile radius may not be cost effective for this to compete with other feeds. Where WDGS is cost-effective even with discounting for transportation costs, it will be used in animal feed. The ISOR indicated that transporting costs may lead to cost-prohibitive environment for WDGS in certain regions/locations. The analysis however did account for DGS being used in the animal feed industry. As for the comment on the fact that DGS is being shipped nationwide and worldwide, it is the dry variety (DDGS) that is being exported and not wet DGS. One commenter [NRDC3] does support the consideration of the challenges to handling, storage and transport of dry and wet DGS as presented in the ISOR. Also, see comment M-2.

Calculi from use of DDGS

M-14. Comment: The statement that the use of DDGS with its inherently higher levels of phosphorus will require the addition of calcium to prevent urinary calculi, particularly in hogs, is incorrect. One commenter indicates that urinary calculi does not occur in swine but could occur in ruminants. Another commenter reports that they have not observed such issues though they have been feeding DDGS for many years. As for DDGS being lower in calcium, this mineral is added even in traditional feed and will continue to be added even when using DDGS to maintain optimal health and growth performance of all animals. Proper calcium to phosphorus ratio needs to be maintained for ensure adequate performance in pigs. (UIUC2, UMN, MASCHOFFS)

Response: Increased levels of phosphorus have been reported to cause urinary calculi in livestock. This condition has been reported mostly for cattle, sheep and other ruminants Increased phosphorus resulting from DDGS use, particularly in higher ratios in diets needs to be adequately compensated with increases in calcium inputs to ensure optimal performance of livestock.

Overall, there are multiple issues that will need to be evaluated when considering the use of DGS as replacement feed for livestock. Some may enhance animal performance as indicated by some respondents based on published literature or personal research studies. Others may lead to suppression of animal performance or other unintended effects due to a host of issues indicated in the staff report. The ISOR served to highlight likely challenges for the use of DGS as a replacement feed given the different inferences drawn by current research and studies. The analysis did however acknowledge that all of the DGS produced would likely be utilized by the livestock market. Also, see comment M-2.

Poultry Issues

M-15. Comment: Use of DGS in broiler, layer, and turkey diets was omitted from the analysis in the Argonne report (Arora et al., 2008). The authors cited that “poultry consumption was excluded because feed composition and performance data available for poultry were insufficient”. While the NASS-USDA (2007) survey did not include poultry data, other sources could have been used as a reference. Therefore, I elected to provide the following summary of DGS usage in broiler, layer, and turkey diets and calculate displacement ratios for common ingredients partially replaced in these diets, and include this information in the final composite displacement ratios for all food animal species.

Current dietary inclusion rates of DGS in broiler diets range from 3 to 15 percent, with an average of 5 percent (Dr. Amy Batal, 2009, personal communication). Commercial layer diets contain between 3 to 12 percent DGS, with an average dietary inclusion rate of 7 percent (Dr. Amy Batal, personal communication). For turkeys, typical dietary DGS use levels are 10 percent, but in 2008, levels of 20 to 30 percent DGS were used when feed prices were extremely high (Dr. Sally Noll, personal communication). Tables 6, 7, and 8 summarize the partial replacement rates of corn, soybean meal, and inorganic phosphate with DGS in broiler, layer, and turkey diets, respectively. The ranges in dietary DGS inclusion rates for broiler, layer, and turkeys used in this analysis result in no change in growth performance compared to feeding conventional corn-soybean meal based diets. (UMN)

Response: The commenter focuses on the non-inclusion of poultry feeding aspects in the DGS studies presented by Argonne and presents work by Amy Batal (see commenter’s letter for reference) which studied inclusion rates of up to 30 percent in poultry. The conclusion provided matches with the conclusion provided in the ISOR that no change in growth performance is considered when using DGS as a replacement feed in animal diets.

Education of Livestock Farmers about DDGS

M-16. Comment: The commenters indicate that the statement “livestock managers generally lack the information they need on the potential advantages of distillers

grains” in the ISOR is incorrect. The majority of livestock nutritionists in the feed industry have extensive knowledge of the benefits and limitations of using DGS as a replacement feed to various livestock and poultry species. The lack of knowledge mentioned in the ISOR may have been true several years ago but not currently. One commenter though acknowledges staff concerns on informational and educational barriers to using DGS. Some of the specific points raised include:

- a. Information is available on DGS from extension web sites, industry publications and guide sheets, through groups such as the Distiller’s Grains Technology Council, National Corn Growers Association, National Corn-to-Ethanol Research Center, Renewable Fuels Association, U.S. Grains Council and is making use of DGS much easier.
- b. Animal nutritionists, agricultural extension agents and livestock managers have spent decades studying, incorporating, and optimizing DGS in the animal feed and ARB has not utilized the available knowledge and expertise of these groups.
- c. There has been a significant amount of research conducted in recent years that has increased our understanding of how to feed DDGS in swine diets. In addition, there is a plethora of information directly related to swine producers to ensure that they have the knowhow to utilize DDGS in the most effective way. Swine producers have embraced the use of DDGS because it is cost competitive compared to other feed ingredients.
- d. DGS has been used for over a century, first in the form of brewers' grains, and more recently, from ethanol plants. There is now broad spread adoption and broad use. The product provides a value added option for nutritionists in ration development. (UMO1, NCERC1, UMO2, UIUC3, UIUC2, UIUC3, MASCHOFF, UAR, UMN, NRDC3).

Response: The ISOR stated that DGS from 15B gallons of corn ethanol production would likely face challenges in widespread adoption as a feed replacement in livestock rations. It did however account for all of the DGS to be consumed by the livestock feed market.

Some of the challenges cited would likely be from variability in quality of DGS from various plants, concerns from enhanced phosphorus, sulfur, etc., which would require an updated assessment of the feed market when all of this DGS becomes available in the market. Livestock managers need to become familiar with all the issues arising from the availability of DGS from 15B gallons of corn ethanol produced by various plants across the country. Also, see comments M-1 and M-2.

DDGS Shelf Life

M-17. Comment: The commenters state that the issues related to shorter shelf life of wet DGS due to spoilage, mycotoxin accumulation, and temperature issues can

be addressed and would not affect the use of wet DGS. Some points specifically mentioned include:

- a. One example is Amish dairy farms in Lancaster County Pennsylvania that have been utilizing wet coproducts for more than a decade. Most often, these small farms will have no more than 35-45 lactating cows.
- b. An ethanol plants' ability to modify drying processes to produce wet, modified or dry products to suit market needs relative to livestock feeding area proximity. Additives and storage methods available to increase storage time beyond 3-7 days. Feed mill and brokers ability to sell smaller lot sizes to farms unable to receive full loads. Research related to DDGS flow agents and pelleting technologies.
- c. There are handling and storage procedures in place that can extend the shelf-life of wet coproducts indefinitely. One of these methods includes utilization of "ag-bags".
- d. Mycotoxins, if present, will be found in the incoming corn at the front end of the ethanol production process. There are numerous rapid test kits the ethanol industry is using to test inbound corn for mycotoxins.
- e. Several approaches have been tested and are now routinely used by livestock producers to store wet distillers grains for prolonged periods of time. (NCERC1, UMO1, UMO2, UCANR)

Response: Although WDGS storage was presented as likely to present some challenges during storage and shelf-life, the final analysis considered by the Board did account for all of the DGS being used by the animal feed market. No penalty was included for any loss from improper storage. Also, see comment M-2.

General DDGS

M-18. Comment: Discussion of antinutritional factors associated with distillers grain demonstrates a lack of understanding of diet formulations. (UMO2)

Response: The analysis presented in the ISOR considered various factors likely to influence DGS use in animal feed. DGS from various plants is likely to have different nutrient and physical characteristics which a feed formulator has to consider when blending DGS as a replacement feed for other traditional feed components. The analysis did not discuss particular animal feed formulations but did consider the fact that diet formulations are complex and use various feed components, supplements, etc. to generate a cost effective ration for the animals. The feed formulations do not always conclude that DGS has to be used in the final feed ration but is dependent on price and quality of DGS and other available components. See also comment M-2.

M-19. Comment: The acceptance of the near infrared (NIR) instrument by the ethanol industry and animal feed industry, which provides fast and accurate testing of major nutrients in DDGS, will assist livestock producers in formulating animal diets more accurately when including DDGS (4). The export of U.S. DDGS has

increased quickly in the past few years and the projection for the export is promising (US Grains Council website). The consumption of DDGS by various animal types might differ in other countries, but the potential to increase the displacement ratio of DDGS is great (Novecta, personal communication). (NCERC3)

Response: The availability and use of NIR instruments for quality control purposes is something each individual feedlot operator will have to consider for their operation. The analysis presented in the ISOR concluded that there are many variables that have to be considered when DGS is used as a replacement feed. It did however account for all of the DGS produced to be used by the feed industry (would definitely include some exports). As for use in overseas markets, the proportional distribution of DGS across the different types of livestock and the replacement ratios are likely going to be different in various countries. The overall ratio of 1:1 will still apply across both domestic and international feed markets for all the reasons presented in the ISOR. Also see comment M-2.

M-20. Comment: The author's review of "three factors to be considered when determining the feasibility of displacing traditional feeds with DDGS" is based more on opinion than on facts. Their analysis of "challenges" is poorly presented and lacks factual evidence to support their argument. The authors present minimal data and have limited knowledge of DDGS consumption by different animal species. Therefore, the authors are not qualified to evaluate a comprehensive report like the "Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis", which is heavily based on animal nutrition and animal performance studies using DDGS as feed. (NCERC1)

M-21. Comment: Animal nutrition expertise is greatly lacking in the discussion on pages C-51 to C-54. The performance of an animal can greatly differ based on the optimization of the ration of feeds provided and the animal's nutritional requirements. There is a great amount of University information on DDGS available. Most nutritionists use the National Research Council publications on Nutrient Requirements of Beef Cattle, Dairy, and Swine as the guide for nutritional composition of feeds. Single stomached animals (swine and rats) have very different digestive capabilities from ruminant animals (cattle and sheep). In most cattle operations, DDGS serves as a protein source and competes with soybean meal, canola meal, and cottonseed for diet utilization. The amount of use in diets will be determined by price. Like all byproduct feeds, there is a limit to the amount that can be included in the diet. On page C-52 it is stated that the nutrient concentrations in DDGS vary considerably. This is normal for by-product feeds and all livestock nutritionist and managers can address that in ration formulation. In almond hulls, the nutritional composition will depend on the fan adjustment that sorts hulls from shell and twigs that have much lower digestibility. Nutritional testing and ration construction using variable products is a normal operation in the industry. This also is applicable to the browning reaction concern stated. The feed is tested in a laboratory and the

price and amount in the ration are adjusted to economically meet the performance needs of the animal. The document presents feeding as a static process, when it is very dynamic with varying animal nutritional needs and ability to adjust the diet to optimize the animal performance based on research and applied feed knowledge. On page C-53 it is stated that “less protein in DDGS is available to the animal”. Ruminant protein utilization is divided into two areas; rumen and bypass. The combination of both these provides the total protein utilization. The quote addresses the rumen protein utilization, but does not recognize the importance of bypass protein. This is an important aspect that needs to be acknowledged. The concerns about lysine, sulfur and phosphorus in DDGS diets raised in the document again indicate the lack of animal nutrition knowledge represented in this section of the document. Ration formulation is again a process of analyzing of the feed’s composition and optimizing the ration of different feed sources and supplements to meet animal requirements for different performance (growth, lactation and pregnancy). All of these concerns can be addressed in the ration formulation. (UCANR)

Response: Some of the specific issues stated by the commenter include:

- a. The performance of an animal can greatly differ based on the optimization of the ration of feeds provided and the animal’s nutritional requirements.
- b. The amount of use in diets will be determined by price.
- c. Ration formulation is a process of analyzing of the feed’s composition and optimizing the ration of different feed sources and supplements to meet animal requirements for performance.

The analysis presented in the ISOR also pertained to the issues stated above. Broadly, the analysis stated that use of DGS as a replacement feed is not straight replacement but has to consider the nutritional requirements of livestock and also compete with other feeds on a cost-effective basis. Therefore, a balanced approach was used to provide a 1:1 displacement ratio for DGS compared to corn. Also, see comment M-2.

M-22. Comment: I would suggest that you determine whether or not DDGS and WDGS offers the suggested benefits in energy savings, and not try to decide whether or not the livestock industry will utilize them as economical feedstuffs. (UAR)

Response: For reasons discussed in the ISOR, the analysis presented in the ISOR was a balanced approach to DGS benefits and allocated a 1:1 replacement credit for DGS from corn ethanol production. As for the use of all DGS, the analysis considered that the DGS from 15B gallons of corn ethanol would be utilized in the animal feed market. Also, see comment M-2.

M-23. Comment: The calculation of the direct GHG emissions from production of corn-derived and sugarcane-derived ethanol is by-and-large solid and consistent with a well-developed body of scientific research. The calculation of the coproduct

credits does, in my view, somewhat overvalue these credits, resulting in an underestimate of the direct GHG impacts of corn-derived ethanol of perhaps 10 percent. (PEERREVIEW3)

Response: The support of the analysis is appreciated. As for co-product credit for corn ethanol, the analysis in the ISOR considered the various factors likely to influence the replacement of DGS in animal feed. Though data and studies to account for the replacement effect of DGS produced from 15B gallons of corn ethanol is currently unavailable, the analysis did allow for all of the DGS produced to find use in the livestock feed market. This is likely since economics will dictate that all of the DGS will find use as animal feed. Therefore the analysis considered a balanced approach to the replacement issue and provided a 1:1 credit for the DGS produced. See also comment M-2.

M-24. Comment: The use of distillers grains by livestock producers has been extensive. It is widely used in beef, dairy and swine diets. Beef feedlots have routinely used distillers grains in diets at levels of 30 to 40 percent of the diet when corn prices were elevated. The issues of nutrient concentration variability, handling and storage, and education of livestock producers limiting use of distillers grains as written in the report is baseless. If this were the case, why are there not mountains of distillers grains around the country now. Some locations of ethanol generation the demand for distillers grains by livestock producers has been greater than supply. (UMO2)

Response: The issues related to DGS presented in the ISOR are real. There are reports of enhanced benefits from DGS use but there are others that report either no improvements or disbenefits when using DGS as a replacement feed. Most of the issues have been presented in the analysis in the ISOR and relate to current knowledge and experience with using DGS in animal feed. Also, see comment M-2.

M-25. Comment: This is important to the LCFS because it quickly changes the assumptions now used in CA-GREET modeling of biofuel production. The CA-GREET model only allows for limited allocation of credits for by-products in the production of oil seeds, with an assumption that the crop is grown on a piece of land exclusively for biofuel feedstock. In the case of the example above, while biofuel feedstock is why investment is occurring, the main initial output for 5 years is food crops (or other annual oil seed crops). This will result in feedstock for biofuel but also increased production of food crops. The agronomic plan for this production effort includes planting of nitrogen fixing crops so that almost no nitrogen fertilizer is required and use of fish pond cleaning residues to minimize fertilizer impacts and optimize lifecycle ARBOn benefits and to minimize water use impacts. (CO2STAR)

Response: The analysis presented by staff in CA-GREET was to provide for co-product credit for DGS which it accounts as coming from corn that was processed into ethanol. The land use change analysis was based on current and future land

conversions required to meet a 15 billion gallon corn ethanol mandate. It does not focus on the prior history of corn cultivation and land conversion which may have had many factors leading to the expansion of cropland (domestic population growth, export market growth, etc.). Also, see comment M-2.

M-26. Comment: ARB Staff's Co-product Deduction Methodology Results in Artificially Deflated GWI Values: We oppose ARB Staff's methodology of subtracting emissions generated during the production of coproducts as falsely deflating the GWI value of a given fuel. The ISOR states: "For a current generation ethanol plant, a co-product produced is dry distiller's grain soluble (DDGS). This can be used as a replacement for traditional feed for livestock. A complete lifecycle analysis requires an appropriate GHG credit be provided to the pathway since the use of this co-product will displace the need to produce the displaced product. For corn ethanol, DDGS could replace feed corn that is used as animal feed. The model therefore has provided a GHG credit to the pathway equivalent to producing 1 pound of feed corn for every pound of DDGS produced." The logic behind either co-product credit approach, displacement ("where co-products from a pathway avoid the production of this from another source or replace the need for an equivalent product") or allocation by attribute ("products of the most value allocated the most burden in the pathway" measured by market value), can underestimate emissions actually generated or purportedly reduced. First, the generation of a co-product does not necessarily lessen the GHG emissions during a particular fuel's lifecycle in reality. The emissions generated during the co-products' production are still occurring as a direct result of the fuel's generation, and just because the co-product is being generated incident to fuel production does not mean that the co-product will avoid production elsewhere even if it "could replace feed corn." For example, if animal feed is generated in tandem with corn-based ethanol, it is not necessarily "displacing" the production of animal feed elsewhere; it is merely adding additional feed to the market, and may cause additional emissions. This is particularly so considering new evidence about the negative effects of corn ethanol regarding antibiotic resistant bacteria growth in ethanol refineries and distillers grains causing increases in *E. coli* 0157 in the guts of cows." The ISOR also states that "in fact, DDGS appears to face significant barriers to widespread adoption as a replacement for corn and soybean meal." In order to justify subtracting the emissions from a co-product's generation from the GWI value of a fuel, the fuel provider would have to somehow guarantee prevention against the generation of an equal amount of emissions elsewhere in the co-product's market. (CERA2)

Response: Co-product credit is an established methodology in lifecycle analysis of transportation fuels to allow for appropriate GHG emissions credit to by-products that are generated as part of the production process of the fuel or fuel blending component. The rationale for this is the co-product will offset the growing or production of a similar (or like) product elsewhere. For corn ethanol production, DGS is produced during the process and this can be used as a feed replacement for corn. The lifecycle analysis charges all of the corn farming emissions to the ethanol pathway and then credits an

amount equal to the displaced corn that will not have to be 'grown' due to the resulting DGS that can replace corn. As for concerns that antibiotics (or other additives) could suppress the use of DGS as animal feed, the analysis presented in the ISOR adopted a balanced approach and considered that the DGS was likely to find a place in the animal feed market. The analysis did however highlight likely concerns to the use of DGS as a feed replacement in livestock feed rations. See also comment M-2.

M-27. Comment: One of the conclusions in Appendix 11 is that DDGS has the same value as corn, but no scientific basis for this conclusion is provided. As pointed out in this report, when DDGS is included in diets fed to swine, DDGS will replace approximately 57 percent corn and 42.5 percent soybean meal. The economic value of DDGS is, therefore, dependent on the price relationship between corn and soybean meal, but because soybean meal is usually much more expensive than corn, the value of DDGS is usually also much greater than the value of corn. Swine producers can, therefore, pay more for DDGS than for corn without increasing diet costs. As illustrated in this report, in most cases, the break even price for DDGS is between 1.2 and 2 times that of corn. (UIUC2)

Response: See response to comments M-2 and M-10.

M-28. Comment: It is my judgment, as an expert in animal nutrition and feed management, that the reviewers on your staff made some highly judgmental interpretations of the report by Arora et al. from the Argonne National Laboratory, and also made some conclusions that were not warranted. These arise from your interpretation of results in three areas:

1. Variability of nutrient content and availability
2. Handling, storage, and transportation of DDGS
3. Education of livestock producers and managers (UAR)

Response: Broadly, there are multiple issues that will need to be evaluated when considering the use of DGS as replacement feed for livestock. Specifically, to respond to the commenter above:

- a. Variability: Different ethanol plants (and even the same plants) have inherent variability in their DGS products. This will lead to variability in nutrient content and availability of nutrients to livestock that is fed DGS.
- b. Handling, storage and transportation: The ISOR cited studies that indicated moisture (particularly for wet DGS), flowability, shelf-life, transportation issues (bins to be leased by DGS shippers and not freight carriers), and other issues that need to be addressed, particularly when the market will likely be flooded with 15B gallon derived DGS in a relatively short period of time.
- c. Education of livestock producers and managers: Though DGS has been used as a feed replacement in livestock rations, variability in DGS quality, availability of DGS when required, cost effectiveness of DGS compared to other feeds available, potential for manifestation of animal health challenges (polioencephalomalacia, urinary calculi, etc.), enhanced phosphorus which will require alternate manure

management practices are some of the many challenges likely to face both the feed formulator and the livestock farmer.

Also, see comment M-2.

M-29. Comment: The commenters have concerns of using DGS as feed replacement in livestock. Food safety is one issue related to antibiotic laden DGS finding a way into humans through the food chain. Another is the reported enhancement of E-coli in cattle fed DGS. One commenter therefore supports the analysis of 1:1 for DGS to feed corn provided in the staff report. The other draws attention to an issue of awarding an equivalent energy credit to DGS when concerns expressed may lead to limited use of DGS as replacement feed. (NRDC3, AIR)

Response: The determination approved by the Board to provide a 1:1 replacement ratio for DGS was based on a balanced approach to awarding co-product credits to corn ethanol for DGS produced as a by-product of the ethanol production process. Though there are studies that extol the benefits of DGS (e.g. better performance), there are similarly concerns such as the ones raised by the two commenters, which may limit the use of DGS as replacement feed. Also, see comment M-2.

M-30. Comment: Many livestock producers prefer the wet form of distillers grains because it can often be purchased at a reduced cost per nutrient basis compared to dry distillers grain. (UMO2)

Response: Wet DGS is utilized by farms in the vicinity of ethanol plants. Generally, beyond a 50 mile radius though, shipping costs are likely to become a factor in the cost-effectiveness of DGS as a replacement feed. Also, shelf life of wet DGS is short (a few days) and long distance transport is not practical due to potential spoilage of DGS. In summary, wet DGS is generally used where available and practical to use. Also, see comment M-2.

M-31. Comment: The Maillard reaction is mentioned as a problem that contributes to low protein utilization (Page C-52). While it is correct that Maillard reactions may sometimes occur during the production of DDGS, it is not correct that this necessarily leads to a low utilization of protein. The Maillard reaction mainly affects the amino acid Lysine and the problem is easily corrected by inclusion of crystalline Lysine in diets containing DDGS. It is, therefore, recommended that if DDGS is included in diets fed to swine, then crystalline Lysine should also be used. (Stein, 2007) Again, if diets are formulated correctly, the protein utilization in DDGS containing diets is similar to that of corn soybean meal diets. (UIUC2)

Response: The analysis presented in the ISOR did indicate that in instances where lysine would be limiting (particularly due to the Maillard reaction issue), supplemental lysine would have to be used to make up for any deficiency in corn based lysine. As for final formulations, DGS only makes up only part of a final feed formulation and the final mix is based on a price/nutrient analysis of all available feed components. If additional

supplements such as synthetic lysine (and others if required) are necessary when using DGS to ensure protein utilization similar to a corn-soybean diet, it does not truly account for DGS providing a comparable or advantageous benefit compared to the baseline feed components. Also, see response to comment M-2.

M-32. Comment: Also, the distillers grains that are a co-product of ethanol production are playing a major role in providing livestock—in the U.S. and abroad—with high-protein, nutrient rich feed. (AFBF, OCGA)

Response: The analysis presented in the ISOR has provided credits to DGS produced during the ethanol production process. The complete use of DGS is accounted for in the analysis. See also comment M-1.

M-33. Comment: Creation of protein as well as other feed products such as forage materials and electricity co-products – Recognize the creation of protein/animal feed and electricity, and include appropriate credits in the lifecycle analysis. (EE1)

Response: The analysis in the ISOR includes a credit for protein (e.g. DGS), a co-product of the ethanol production process. As for electricity or other co-products, where applicable, plants could submit an application under Method 2A to the Board to be considered for inclusion. Therefore provision is available in the regulation for appropriate crediting where applicable.

M-34. Comment: The commenter indicates that with the expansion of ethanol plants in CA, the by-product of the process is used as animal feed and therefore the production of milk has to be considered as a by-product and appropriate credit has to be given to the ethanol plant. (ERG1)

Response: A credit is provided for DGS produced as a by-product of the corn ethanol production process. This credit is provided for DGS replacing corn in animal feed. Actual production of milk is not related to the ethanol production process.

M-35. Comment: Transportation and handling of DDGS has occurred in California. I have observed large and small operations using the product and all have adapted systems to utilize the product without problems. Feed utilization is based on price for energy and protein content. If livestock producers find a lower priced product, they quickly invest in proper storage and feeding infrastructure. With 1.6 million dairy cows in California, at the right price and location of plants in the dairy production areas, transportation and utilization of WDGS would not be a problem. (UCANR)

Response: The analysis presented did account for all the DGS from 15B gallons of corn ethanol to find use in the feed market. This is given that it will be priced competitively given the enormous quantities of DGS likely to result from 15B gallon production. As for Wet DGS, producers will shift between wet and dry depending on

transport costs, local demand, cost competitiveness of wet feed, etc. See also response to Comment M-1.

M-36. Comment: As an example, corn ethanol biorefineries operating in California are the most efficient, least greenhouse gas emitting plants in the country while at the same time they produce a high value feed product for our dairy and beef industries. They also provide the platform to move expeditiously towards advanced lower ARBon biofuels, something our members expect to benefit from in the near future. (AGBC)

Response: The analysis presented in the ISOR accounts for the feed generated by ethanol plants in CA and have provided co-product credits for both dry and wet DGS. The regulation also provides a mechanism via Methods 2A and 2B to create additional credits if plants can demonstrate such benefits.

M-37. Comment: Composition of DDGS and digestibility of nutrients. A large number of research projects have been completed with DDGS and there is a large database for nutrient composition of DDGS (Spiehs et al., 2002). Results of this research have documented that the concentration of digestible energy in DDGS is similar to that in corn and slightly greater than in soybean meal (Pedersen et al., 2007; Stein et al., 2009). This means that when DDGS is included in diets fed to pigs, the energy concentration will not be reduced. (UIUC2)

Response: The analysis presented in the ISOR considered a balanced approach and provided a 1:1 displacement credit for DGS relative to corn. This implicitly provides an equal energy credit for DGS relative to corn.

M-38. Comment: The commenter states that lower methane emissions due to shorter lifetimes in the farm (cattle are fattened faster with DGS use) before cattle are slaughtered for meat would require credits to be provided to corn derived ethanol. Also, a claim is made for providing GHG credits for reduction in synthetic phosphorus use in animal diets due to enhanced phosphorus digestibility when using DGS. (RFA1)

Response: As provided in the response to Comment M-1, enhancements reported in a survey of controlled studies conducted do not necessarily reflect a clear picture of the use and benefits for all of the DGS produced by 15B gallons of corn ethanol production. The studies reported above have not reported if the feed rations were economically optimized since actual use of DGS will depend on its cost-effectiveness compared to other feeds available in the livestock feed market. Also, studies reporting any change in enteric fermentation due to change in feed rations is not available to assess changes from existing patterns. As also indicated in the response to Comment M-2, availability of data and studies to account for DGS from 15B gallon ethanol production will allow for refinement of the current analysis.

Phosphorus enrichment in DGS is likely to manifest itself via enhanced phosphorus in manure, a likely environmental concern for many regions in the United States. As for phosphorus digestibility in swine, there are studies that have reported better digestibility but details of additives in feed (such as phytases) have not been provided which could explain changes in phosphorus digestibility. As indicated in the response to Comment M-1, availability of data and studies in the future will allow for any refinement to be made to this if necessary.

M-39. Comment: Credit for distillers grains and solubles but inadequately identifies the sources on which its assumption relies. A University of Nebraska study published on March 31, 2009, further documents the prevalence of unreported and outdated sources used in calculating the co-production credit in the CA-GREET model. Again, the use of historic data to fix ARBon intensity values in a Lookup Table inherently overstates the ARBon intensity of com ethanol. (NOVOZYM1)

Response: The ISOR provided a rationale for the 1:1 displacement ratio used in the co-product analysis of DGS from corn ethanol. All of the reports and articles referenced were clearly identified in the ISOR. For other data, currently available data was used for the corn ethanol pathway and has been documented in the pathway document for corn ethanol. The CA-GREET model has also been made available on the LCFS website. When additional data becomes available, appropriate refinements will be considered. As for process updates, Methods 2A and 2B have been included in the regulation to allow stakeholders to participate in the LCFS by providing documentation to ARB to approve a ARBon intensity for a specific plant or new pathway.

M-40. Comment: Under “Staff Recommendations” (page C-54) it is postulated that “it is evident that significant barriers to the widespread adoption of DDGS as livestock feed exist”. The reality is that swine producers, like other livestock and poultry producers, have been amazingly quick to adopt and embrace feeding diets containing DDGS. The total usage of DDGS in diets fed to swine in the US has increased from around 100,000 Metric tons in 2001 to more than 3 million Metric tons in 2008. From this usage it is evident that swine producers have been exceptionally successful in taking advantage of the opportunity of feeding DDGS to swine. (UIUC2)

Response: The analysis in the ISOR did account for the DGS resulting from 15B gallons of ethanol production as being used by the livestock industry. With DGS becoming widely available from the increased corn ethanol production, it has found expanded usage among various livestock industries. The analysis presented considered swine feed industry as being one among many livestock industries that would utilize DGS as a replacement feed. See also response to Comment M-1.

M-41. Comment: Allowing co-product credits, (even if it is "discounted" by a percentage for the "new market effect"), artificially deflates a given fuel's GWI value making it appear as if the fuel is "cleaner" than it actually is. The danger of

this co-product methodology was evidenced when Dr. Caswell with the University of Nebraska presented his BESS model at the January 17, 2008, LCFS workshop, asserting that within his model, "Co-product credits represent 20-40 percent of life-cycle GHG emissions." Only through the allowance of such a high ratio of co-product credit was Dr. Caswell able to calculate that "Compared to gasoline, typical USA corn-ethanol systems reduce GHG emissions by an average of 43-58 percent, but the full range is 17-65 percent due to different biorefinery designs, energy sources, and crop production practices." As was noted at the workshop, his model fails to include emissions from criteria and toxic pollutants and any land use change values at all, and thus, his GWI calculations fail for these reasons as well. Fundamentally, however, co-product credits should not be allowed to manipulate the GWI value of a given fuel when they do not reflect "real," "verifiable," nor "quantifiable" emissions reductions, as required under § 38562(d)(I) of AB 32.

Awarding co-products credit in the default value of a fuel assumes that all fuel providers of that particular fuel engage in equivalent co-product generation as well. For example, the ISOR estimates that "new plants are projected to be dry-mill only" and that "newer plants in operation or under construction in California are energy efficiency, maximize co-product value, and produce lower-ARBon intensity ethanol." Thus, a producer of corn-based ethanol would benefit from the assumption in corn based ethanol's default value that it was "maximizing co-product value," when it is not in fact doing so, falsely reflecting the GWI of its fuel. Meanwhile, an ethanol company that was actually producing more animal feed than the default assumption would be given the option of providing a "better value for its feed" and awarded an even lower GWI value for its ethanol, again, not reflecting actual emissions reductions in the real world if it was merely adding more feed to the market. (CERA2)

Response: Assertions made by researchers at the University of Nebraska which the commenter refers to here has not been utilized in their analysis of co-product credit in the ISOR. Although the analysis in the ISOR which was approved by the Board includes estimates for ARBon intensities for various facilities, when a product from a plant will be participating in the LCFS, they will be required to provide data to support their performance characteristics. As for the statement that plants producing more feed than estimated by the default analysis, any applications to develop a separate ARBon intensity (under Method 2A) will require complete review of the entire pathway. In approving the staff recommendation as detailed in the ISOR, the Board directed staff to re-visit this issue. Any refinements to the current analysis would be considered by the Expert Workgroup (directed to be established by the Board per Resolution 9-31, page 15) to be formed by staff with a report due to the Board by December 2010 and also during two mandatory program reviews to be done in 2011 and 2014. See also response to Comment M-1.

M-42. Comment: There is little in the scientific literature that substantiates the protein digestion estimates presented in the appended report. A cursory review of the

relevant literature leads to the conclusion that protein in distillers grain is extensively digested by small intestinal and pancreatic proteases. (UMO2-2131)

Response: The analysis presented in the ISOR provided results from published literature which discussed protein digestibility of DGS. The Board's analysis did not base its assessment on specific digestibility of proteins in livestock but used a balanced 1:1 displacement ratio for DGS compared to corn. In approving the staff recommendation as detailed in the ISOR, the Board considered the evaluation of this issue and recognized that new data from studies in the future may allow for refinements of the current analysis. Any new information would be considered by the Expert Workgroup (directed to be established by the Board per Resolution 9-31, page 15) to be formed by staff with a report due to the Board by December 2010, and also during two mandatory program reviews to be completed in 2012 and 2015. See also response to Comment M-1.

M-43. Comment: There is zero displacement of food acreage by fuel acreage. And the average person is overweight. Corn ethanol for example is also feed and food, not just fuel. Only the starch in feed corn goes to ethanol, which cattle and dairy cows have difficulty digesting. The byproduct of corn ethanol, high protein distillers grains is a better feed product than the whole corn itself. It's what you call a value-added product. This corn ethanol byproduct supplements a large livestock, dairy, poultry, and fish farming industry. (UCSB)

Response: We agree with commenter that DGS is a feed replacement that supplements a large livestock industry. The analysis presented in the ISOR lists various issues likely to be a factor when utilizing DGS from 15B gallons of corn ethanol as a replacement feed. As for the comment on 'zero displacement of food acreage by fuel acreage', the GTAP analysis indicates that corn diverted to producing fuel has the unintended effect of converting additional land to meet the shortfall in corn (or other displaced feed crop). This translates to requiring new land to grow additional crop and based on this analysis, we disagree with the commenter that there is zero displacement of food acreage by fuel acreage as stated above. Also, see response to comment M-2.

M-44. Comment: It is a shame that the co-products credit analysis and the ILUC portion of the regulation have not been afforded the same rigor. The fact that they haven't reflects poorly on the credibility of the entire regulation. (SHAFFER)

Comment: The Regulations Should Provide A Rational, Consistent And Transparent Co-product Methodology: The choice of co-product methodology has a big influence on the well-to-wheel ARBOn intensity. ARB should choose methodologies for co-products of individual fuel pathways based on sound and transparent principles, which are consistent with the goals of the LCFS. As yet the principles have not been defined. (SHELL).

Response: The original Purdue GTAP model did not include credits for co-product but a module was developed specifically for the LCFS analysis. The model was 'run' with

and without co-product crediting to calculate the impacts of co-products and the results seemed to conform to estimated co-product credits. As for CA-GREET analysis, co-product credit methodologies were discussed in detail for many of the pathways at several workshops conducted as part of the LCFS regulatory process. At the workshop on January 17, 2008²⁷, it was indicated that displacement would be the preferred methodology but other approaches would need consideration where displacement could prove burdensome to the lifecycle analysis. The other methods include allocation based on mass, value or energy. The analysis used for the various fuel pathways published include co-product credits based on either displacement or allocation methods. Staff has therefore worked to be consistent within the available co-product crediting schemes discussed at the public workshops. All of the pathway documents published through September 2009 clearly specify the methodology used in co-product treatment. The Board in approving the ISOR directed staff to establish an Expert Workgroup to further refine some areas such as Land Use Change and provide recommendations by December 2010. Based on the recommendations, staff may make refinements to the current analysis. Also there are two mandatory program reviews in 2011 and 2014 when any other refinements could be considered.

M-45. Comment: The impacts of utilizing the BTU-based approach are significant. With the current displacement method, the GHGs associated with ethanol production from a natural gas dry mill are 69 g CO₂eq/MJ (excluding land use change emissions). With the BTU-based approach, where the energy used in farming and at the plant is allocated to the products on the basis of their final energy content (consistent with ARB biodiesel approach), the GHGs associated with ethanol production from the same plant are 47 g CO₂eq/MJ, according to our modeling with CA-GREET1.8B. This represents a 32 percent decrease from the ARB on intensity value derived from using the displacement method. (RFA1)

Response: See response to comment M-53. Displacement was the adopted method for corn ethanol and staff feels that this is the most appropriate co-product treatment for this pathway. A preliminary draft version of soybean biodiesel utilized a co-product credit based on energy but this is being currently reviewed and updated information will be published when it is complete. See also response to comment M-1 and M-47.

M-46. Comment: ARB should, in our view, use a consistent co-product allocation method. Employing the displacement method for corn-based ethanol and the energy allocation method for soy-based biodiesel defies logic given their inherent and rather obvious similarities. No other government does it this way. This decision is particularly harmful because the chosen methods result in the worst possible assessment for each fuel. And in the case of soy-based biodiesel, the error is compounded because ARB adds GHG emissions associated with the inefficiency inherent in livestock feed uptake to the oil/biodiesel side of the equation. This is illogical since the amount of energy that animals metabolize has nothing to do with the oil/biodiesel side of the GHG assessment; those GHG

²⁷ See the document and presentation on January 18, 2008 workshop retrieved from this website: http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings.htm

emissions should be counted on the meal side since they are related 100 percent to livestock feeding within the animal production industry. Further, it is important to understand that soybean oil has historically been viewed by the soybean industry as a by-product rather than a co-product. Even with the development of biodiesel, the majority of the value of a soybean continues to reside in the meal. As such, it is common knowledge that farmers grow soybeans for the meal and not the oil. This makes it doubly inaccurate to add GHG emissions associated with meal/livestock feed to oil/biodiesel. (ABC INC)

Response: Staff has therefore worked to be consistent within the available co-product crediting schemes discussed at the public workshops. For soybean biodiesel, current updates are investigating the impacts of some of the issues being raised in the comment above. The analysis for soybeans does not consider inefficiencies of animal metabolism. Also, the current updates in progress are focused on appropriate adjustments to co-product credits to the biodiesel pathway based on refinements to the soybean meal crediting methodology. As for the statement that ‘farmers grow soybeans for the meal and not the oil’, for a consistent lifecycle analysis of a fuel, any product or co-product has to be assigned a debit (or credit) of GHG emissions. For the soybean case, when oil is produced by pressing the soybeans, GHG emissions from growing (and transporting and other operation) has to be proportionally allocated to both the soybean meal and the oil produced. Only the GHG emissions attributable to the oil is added to the biodiesel pathway. This will be made available on the LCFS website when an updated version of the soybean to biodiesel pathway document is published in November 2009.

M-47. Comment: We are concerned with the allocation treatment of distillers grains for corn ethanol in California GREET 1.8B. There are two issues with how CA-GREET1.8B estimates the energy credit of distillers grains. First, the CA-GREET 1.8b model assumes that DGs replace only corn. This has been shown to be faulty assumption based on the detailed research by Argonne referenced earlier in these comments. Further, this parameter varies from the default Argonne GREET 1.8b assumptions. DGs replace both corn and soybean meal. Second, ARB is utilizing the displacement approach for allocating energy to ethanol and DGs. However, ARB should use the BTU-based allocation method instead, and for two reasons:

1. ARB is using the BTU-based method for the soybean meal co-product produced at a biodiesel plant.
2. DGs produced at an ethanol plant have higher energy content than the corn used in the plant to produce ethanol. This is clearly shown in Table 2 of the Argonne report, and demonstrated by the fact that 1 lb of DGs replaces 1.28 lbs of feed. Therefore, some of the energy used in the plant to produce both ethanol and DGs, which is now all being allocated only to ethanol, should be allocated to DGs as well. And, the best method of doing this is to utilize the BTU-based allocation method. (RFA 3556)

Response: The analysis presented in the ISOR reviewed the analysis presented by Argonne but based on other studies available (see rationale detailed in Appendix C11 of the ISOR), concluded that at present, a 1:1 credit for DGS was adequate. When the full impact of the DGS from 15B gallons of corn ethanol becomes available, appropriate refinements to the current analysis could be considered. The Expert Workgroup being established per the direction of the Board in Resolution 09-31 may consider this issue among the various issues that will be reviewed for refinement. This group will report back to the Board by December 2010. Also, any updates to the current analysis could be considered during the two mandatory program reviews in 2011 and 2014.

Displacement was the adopted method for corn ethanol. All of the pathway documents published through September 2009 clearly specify the methodology used in co-product treatment. A preliminary draft version of soybean biodiesel utilized a co-product credit based on energy but this is being currently reviewed and updated information will be published when it is completed. See also response to comment M-1.

M-48. Comment: In evaluating the CA-GREET 1.7, it appears the allocation method for ethanol is displacement, but the allocation method for biodiesel is energy content. When allocating for ethanol using the displacement method, DGS displaces soybeans and feed corn. The energy and emissions associated with soybeans has to be calculated in order to know the emission credits for DGS. The calculation for the soybean emissions is done using displacement in the Biodiesel pathway for the ethanol LCA. So, in a sense these two pathways are connected. On one hand, the biodiesel ARB on intensity is calculated using energy content, but when the ethanol co-product credits are being calculated for the ethanol pathway, the soybean value is being calculated using displacement. The methods are not consistent. ADM requests that ARB explain the logic used to conclude that displacement allocation be used for ethanol while energy content allocation be used for biodiesel. (ADM)

Response: The co-product credit for corn ethanol from DGS utilizes a 1:1 credit based on mass and does not include any credit from displacement of soybeans. The rationale was explained in Appendix C11 of the ISOR. With this analysis, there is no inconsistency for any displacement credit for the corn ethanol pathway. Also, see comment M-47.

M-49. Comment: Co-product treatment method has a large impact on the GHG savings reported. There is no internationally agreed and consistent approach. (VALENTE)

Response: International Organization for Standardization (ISO) guidelines exist for co-product crediting but are not very specific recognizing the likely challenges (creates undue burden on the pathway analysis) that specific pathway analysis could create for the analyst. As part of regulatory process, staff conducted several workshops and relevant methodologies for use in the LCFS process were discussed extensively at these workshops. Fuel pathways with appropriate co-product credits were published for

public comments and appropriate refinements were made when relevant to the pathway analysis. The entire process was open and all co-product assignments were made on a technically relevant basis. Staff recognizes that certain jurisdictions based on local mandates may offer alternate crediting methodologies but with global adoption of low ARB on fuel standards in the future, harmonization will be a likely goal for all regulatory entities involved in such efforts.

M-50. Comment: Consistent methodology is a priority. It is not our intent to cause Biodiesel to lose the fossil credit. We just want equal treatment. That also implies that it is also appropriate to take a fossil energy credit for glycerin used as boiler fuel. If Biodiesel production increases as significantly as the compliance scenarios indicate, fueling glycerin is a reasonable boundary assumption. (A2O)

Response: Currently, glycerin has been provided with a co-product credit based on an energy allocation method. If glycerin is used as a boiler fuel to offset some of the energy requirements of a biodiesel plant, this could be reviewed under Method 2A and the producer, with verifiable information could submit an application requesting an alternate pathway ARB on intensity.

IV. SUMMARY OF COMMENTS MADE DURING THE FIRST 15-DAY COMMENT PERIOD AND RESPONSES

The table below identifies the 36 comments received during the first 15-day comment period. It provides a correlation between (1) the abbreviation used in this Section V to refer to a comment letter; (2) the number assigned to the comment letter in the listing (with links) on ARB's website for this rulemaking of all written comments received in the rulemaking; and (3) the name of the person(s) signing the comment letter. These letters were received between July 20, 2009 and August 19, 2009.

Abbreviation	Letter #	Commenter
A204NESTE3	10	Cal Hodge, A2O Inc. on behalf of Neste Oil Written testimony: August 18, 2009
A204NESTE4	11	Cal Hodge, A2O Inc. on behalf of Neste Oil Written testimony: August 18, 2009
AMYRIS	32	Fernando Garcia, Amyris Biotechnologies Written testimony: August 19, 2009
BP3	35	Ralph Moran, BP America Written testimony: August 19, 2009
CALETC3	37	David Modisette, CA Electric Transportation Coalition Written testimony: August 19, 2009
CE5	36	Todd Campbell, Clean Energy Written testimony: August 19, 2009
CNAES2	24	Thomas J. Corcoran and Kurt E. Blase, Center for North American Energy Security Written testimony: August 19, 2009
CNGVC3	33	Pete Price, California Natural Gas Vehicle Coalition Written testimony: August 18, 2009
CONOCO2	31	H. Daniel Sinks, ConocoPhillips Written testimony: August 19, 2009
COULOMB	13	Richard Lowenthal, Coulomb Technologies Written testimony: August 18 2009
DARLING	4	C. Ross Hamilton, Darling International inc. Written testimony: August 17, 2009
EMBRAPA	7	Claudinei Andreoli, Embrapa Written testimony: August 17, 2009
EUREKA	23	Philip Miller, Eureka Seeds Inc. Written testimony: August 19, 2009
FISHER1	1	Robert E. Fisher Written testimony: May 12, 2009 (error in date log)
FISHER2	2	Robert E. Fisher Written testimony: May 16, 2009 (error in date log)
FISHER3	3	Robert E. Fisher Written testimony: May 21, 2009 (error in date log)

Abbreviation	Letter #	Commenter
GE4	17	Tom Buis, Growth Energy Written testimony: August 19, 2009
GE5	18	Tom Buis*, Growth Energy; Bruce E. Dale, Michigan State University; James Michael Lyons, Sierra Research Written testimony: August 19, 2009
ILCORN2	28	Rob Elliot, Illinois Corn Growers Association; John Holzfaster, Nebraska Corn Board; Kenneth Copenhaver and Steffan Mueller, University of Illinois-Chicago; Rita Mumm, University of Illinois Urbana Champaign; Gary Edwards, Iowa Corn Growers Association; Raymond E. Defenbaugh, Illinois Renewable Fuels Association; Mike Edgerton, Monsanto; Hans Stein, University of Illinois Urbana Champaign Written testimony: August 19, 2009
LACSD	8	Stephen R. Maguin and Gregory M. Adams, Los Angeles County Sanitation Districts Written testimony: August 19, 2009
LINDE	16	Mike Beckman, Linde LLC Written testimony: August 19, 2009
MACQUARIE	14	John Mathews, Macquarie University (Australia) Written testimony: August 19, 2009
MELVER	12	Naomi Melver Written testimony: August 18, 2009
NBB2	5	Shelby Neal, National Biodiesel Board Written testimony: August 14, 2009
NCB2	6	F. Jon Holzfaster and Don Hutchens, Nebraska Corn Board Written testimony: August 18, 2009
NCGA2	29	Bob Dickey, National Corn Growers Association Written testimony: August 19, 2009
RFA3	38	Geoff Cooper* and Bob Dinneen, Renewable Fuels Association Written testimony: August 19, 2009
SEMPRA3	25	Michael J. Murray, Sempra Energy Written testimony: August 19, 2009
SEMPRA4	26	Michael J. Murray, Sempra Energy Written testimony: August 19, 2009
SPT1	20	Kirk Cobb, Superior Process Technologies Written testimony: August 19, 2009
SPT2	21	Joseph M. Valdespino, Superior Process Technologies Written testimony: August 17, 2009
SPT3	22	Joseph M. Valdespino, Superior Process Technologies Written testimony: August 19, 2009
TESORO3	19	Dan T. Riley, Tesoro Corp. Written testimony: August 19, 2009

Abbreviation	Letter #	Commenter
UNICA2	15	Calvin Hamilton, Darling International inc. Written testimony: August 17, 2009
WM4	27	Chuck White, Waste Management Written testimony: August 17, 2009
WSPA4	34	Catherine Reheis-Boyd, WSPA Written testimony: August 19, 2009

The First 15-Day Change Notice was issued July 19, 2009 with an August 19, 2009 comment deadline. It solicited comment only on the limited number of additional regulatory modifications being made available and nine additional documents being added to the rulemaking record, including seven pathway documents. The regulatory modifications consisted of:

- (1) Changes to section 95480.1(a) and (d) regarding the effective date of the various provisions (reporting and recordkeeping requirements and violations provision starting on January 1, 2010 and the remaining provisions starting on January 1, 2011) and the inclusion of an exemption for military tactical support equipment, respectively;
- (2) Changes to section 94581 to clarify the definition of “biogas,” add a definition for “liquefied petroleum gas (LPG or propane),” and delete definitions for “oil sands” and “oil shale;”
- (3) Changes to section 95484(c)(3)(C) on the reporting requirements for residential charging stations;
- (4) Changes to section 95484(d)(2) (Demonstration of Physical Pathways) to allow demonstrations by non-regulated party fuel providers, clarify the effects of a material change or non-material change on an approved physical pathway, clarified the extent to which LCFS credits can be retroactively applied for an approved physical pathway, and requiring the posting on ARB’s website of specified information regarding approved physical pathways;
- (5) Changes to section 95485(c) to clarify the constraints on exporting LCFS credits;
- (6) Changes to section 95486 to incorporate the Carbon Intensity Lookup Tables (Tables 6 and 7) into the regulatory text, delete the language providing for Executive Officer certification of carbon intensity values, incorporate by referencing the pathway supporting documents, provide language for the deficit treatment of high-carbon intensity crude oil, and specify that the Method 2A and 2B approval process would be consistent with the rulemaking provisions of the Administrative Procedure Act;

- (7) Changes to section 95489 to add specific provisions mandating two program reviews and governing the scope of and process for conducting those reviews; and
- (8) Pursuant to the Board's directive in Resolution 09-31, the addition of a new section 95490 permitting the Executive Officer to enter into enforceable written protocols with regulated parties under the specified conditions.

Despite the First 15-Day Change Notice's statement that "only comments relating to the modifications to the text of the regulation or to the additional documents and information referenced above shall be considered by the Executive Officer," several parties submitted comments on other topics not covered by the Notice. Comments on such other topics are generally not summarized or responded to in this Section IV. of the FSOR. This includes comments in CE5 on the opt-in fuels exemption, the deficit carryover provision, the Energy Economy Ration (EER) for diesel vehicles, and the EER for heavy-duty natural gas vehicles; comments in A204NESTE3 on renewable diesel and multimedia evaluations; comments in LACSD on the requirement that biogas meet the State's motor vehicle fuel specifications; comments in WSPA4 suggesting a different definition for "importer;" and comments in CNGVC3 on inclusion of fossil LNG in the opt-in fuels list and on the EER for heavy-duty natural gas engines.

Additionally, this Section IV. does not, except as otherwise noted, summarize or respond to comments supporting various elements made available for comment by the First 15-Day Change Notice, including LACSD's support on physical pathway demonstrations by non-regulated parties, the export of LCFS credits, language in the Method 2A/2B provisions, and the enforceable written protocols provision.

Despite falling outside the scope of the Second 15-Day Change Notice, a number of comments nevertheless are summarized and responded to, as noted below. Although ARB legally is not required to summarize and respond to these comments under the APA, we provided a response to these comments because it was felt the general public and interested stakeholders could benefit from the additional clarity provided by the responses.

A. Land Use Change and Other Indirect Effects

General Land Use

IV-1. Comment: An analysis prepared by the Renewable Fuels Alliance (“RFA”) demonstrates, conversely, that when other predictive methods are applied, there may be no land-use change at all, as a result of a decision to use the corn ethanol pathways. (GE4)

Response: ARB has received and reviewed the report prepared by RFA. Since the Informa Economics analysis that forms the basis for the RFA report was not submitted for review, an in-depth assessment of the analysis results could not be made. The key argument presented by RFA is that land use changes that occur outside the U.S. are not attributable to U.S. corn ethanol production since their modeling predicts that U.S. exports remain constant between 2001 and 2015. This result is predicated on large increases in crop yields (greater than those predicted by USDA) and a large decrease in cotton exports and land devoted to cotton production. They acknowledge that increased demand for cereal grains will occur due to increasing world population and increasing consumption of protein. They also estimate that total major crop area in the world will increase from 827.5 to 903.2 million hectares between 2001 and 2015. They assert, however, that none of the increase in crop area occurring outside the U.S. can be attributed to U.S. corn ethanol production if U.S. exports remain constant over this time period. However, one could argue that if U.S. corn ethanol production did not increase over this time period, U.S. exports would increase as yields increase thereby resulting in less global land conversion required to meet increasing food demand. This argument raises the fundamental policy question: is the primary purpose of future increases in U.S. agricultural production to provide food for a growing world population or is the primary purpose to provide feedstock for fuel? ARB rejects the argument that the U.S. is not at least partly responsible for meeting the increase in world demand for food.

The LUC analysis conducted by ARB attempts to answer an entirely different and more appropriate question: *What is the net change in land used globally for agriculture in direct response to an increase in crop-based biofuel production?* The GTAP modeling used by ARB is designed to project the specific effects of one carefully-defined policy change – namely the increased production of a biofuel. In other words, the GTAP modeling estimates the difference between global land use for agriculture with an increase in biofuel production and global land use for agriculture without an increase in biofuel production. This difference is then correctly attributed to expanded biofuel production.

In order to answer the more appropriate question posed by ARB, RFA must repeat its analysis without the increase in biofuel production. Again, the difference between global land use for agriculture with an increase in biofuel production and global land use for agriculture without an increase in biofuel production gives the appropriate value to attribute to the increase in biofuel production.

IV-2. Comment: While Sheehan (2009) may not have been in the record previously, the RFA analysis certainly was; but it has been ignored and has not received either internal ARB review or external peer review under ARB supervision. Unless it can explain why the RFA analysis and that of Sheehan (2009) are both incorrect, ARB must conclude that reliance on the corn ethanol pathways will not result in “leakage” under the 2006 Act. To date, ARB has not addressed the RFA analysis and Sheehan (2009). (GE4)

Response: ARB has not ignored the land use change analysis submitted by RFA. See response to the previous comment.

Sheehan uses a dynamic land use model developed by SheehanBoyce, LLC. To our knowledge, this model has not been peer reviewed and, in fact, the report submitted to ARB is a draft report that has not been published. As stated in the draft report, “SheehanBoyce, LLC has constructed a very simple system dynamics model to look at the physical stocks and flows of land movement in agriculture.”

Although a lack of a copy of the model and specific model inputs precludes an in-depth analysis of the modeling, our brief analysis of the Sheehan report leads to the following assessment:

First, we believe that Sheehan has presented a thoughtful (but preliminary) analysis and we do agree with several points made in the report including the following: “Early arguments from biofuels advocates relied heavily on the uncertainty and complexity of indirect land use change as a basis for saying that it should not be included as part of the regulatory framework for biofuels (Kline, & Dale 2008). This is an argument based on obfuscation, and not a legitimate basis for ignoring land use change effects.” Sheehan does not dispute the existence of land use change emissions and in fact the modeling includes both emissions from land use change and opportunity cost (or lost resequestration).

Second, as Sheehan correctly points out in the report, if the increasing world demand for food crops meets or exceeds the increasing production of food crops due to yield changes, then any additional demand for land from biofuels will, by definition, lead to an incremental amount of new land being cleared for agriculture. As shown in both the Sheehan and RFA reports, the increasing world demand for food crops meets or exceeds the increasing production due to yield changes through at least the year 2015. Therefore, any expanded biofuels production occurring before this date will lead to an incremental amount of new land being cleared for agriculture. Furthermore, even if increasing production due to yield changes outpaces increasing world food demand, use of productive farmland for biofuels will result in an opportunity cost or lost sequestration effect associated with the notion that excess land would have reverted to its native state (e.g. grassland or forest) if it were not diverted to energy crop production. This opportunity cost may be significant for productive farmland that can naturally support regrowth of forest. Although the Sheehan model properly incorporates an

opportunity cost, we do not see evidence that this opportunity cost captures the potential for forest regrowth. We have recognized this asymmetry between afforesting and deforesting regions in our GTAP work; if it can be persuasively shown that the whole world will in fact be losing cropland to pasture/forest as the Sheehan model predicts, it would be appropriate to recalculate land use change, but this study is not persuasive evidence of that condition.

Thirdly, the report correctly points out many potential shortcomings of a dynamic modeling approach. These shortcomings include:

- The FAO data sets used to extrapolate future trends are not entirely reliable. Global data is inconsistent across countries.
- It is reasonable to question the ability to continue historical yield growth rates.
- Per capita demand for food may actually rise faster than historical rates would predict because of the rising incomes in many of the developing nations.

Finally, an extremely important aspect of using a dynamic modeling approach for predicting changes in future land use is that all factors that may affect land use be accounted for. The modeling performed by Sheehan does not do this. As stated in the Sheehan report: “The model includes a number of simplifying assumptions. It looks only at the effect of introducing dedicated energy crops on prime agricultural land...It ignores all other biofuels demands (for corn ethanol, biodiesel, sugarcane ethanol or other advanced crops).” Therefore, the results presented in the paper for carbon debt resulting from increased cellulosic biofuel production are largely irrelevant because projected increases in demand for other biofuels are not included in the demands placed on land in the model (e.g. the Renewable Fuels Standard mandates for 15 billion gallons of corn ethanol, 4 billion gallons of advanced biofuels, and 1 billion gallons of biodiesel as well as European Union mandates for biofuels).

For reasons explained in the response to this comment and the response to the previous comment, we reject the conclusion made by the commenter that the RFA and Sheehan analyses show that “reliance on the corn ethanol pathways will not result in ‘leakage’ under the 2006 Act.”

However, in recognition of the complexity of land use change modeling and other issues relevant to land use change calculations as pointed out in both of these reports, the Board directed the staff in Resolution 09-31 to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. The Executive Officer was directed to return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified through the Expert Workgroup.

IV-3. Comment: RFA has also provided a significant amount of third-party research to ARB staff regarding the land use credit associated with distillers grains (DG), the animal feed co-product of ethanol production. The assumptions used on DG feeding practices have a large effect on the ILUC value of corn ethanol. For

example, utilizing the proper credits for distillers grains would reduce the land use emissions of 15 to 17 g/MJ (from point 3 above; i.e., accounting for revised expansion elasticity) to about 8 to 10 g/MJ. ARB disregarded detailed analysis on DG feeding practices from the Department of Energy's Argonne National Laboratory, as well as information and data from internationally recognized animal scientists from the Universities of Arkansas, Minnesota, Illinois, and Missouri. Several of these professors recommended that ARB alter its DG assumptions and many suggested using Argonne's DG assumptions. ARB still has not provided a defensible reason for disregarding this information and the ISOR appendix on this issue is severely lacking in justification. For the foregoing reasons, ARB should revise its approach to the DG credit and should at least consider the information from Argonne Lab. ARB has provided no valid reason for disregarding this data. Such action is both arbitrary and deprives the rule of the evidentiary support required for finalization. (RFA3)

Response: See response to Comment M-1.

IV-4. Comment: The 30 g/MJ should be revised to 28.3 g/MJ to be consistent with ARB's intent in the ISOR. ARB staff did not disagree with this assessment in an April 16 meeting with RFA. We note that RFA has repeatedly sought clarification from ARB on whether the agency inadvertently omitted this factor. ARB staff has not responded to our request for clarification on this issue. It appears likely that this was an oversight and if it was, it must be corrected prior to sending the rule to the Office of Administrative Law (OAL). (RFA3)

Response: We agree that a mistake was made in the Staff Report's description of the emission factors used for modeling land use change. However, the mistake does not result in a downgrading of the 30 g/MJ value to 28.3 g/MJ. Instead, the mistake calls for correcting the assumption shown in the Staff Report, as discussed below. This typographical error in the Staff Report has been corrected in an errata to the Staff Report. However, for the reasons discussed below, this mistake ultimately did not affect the 30 g/MJ and 46 g/MJ values for the "Land Use or Other Indirect Effect" entries shown for the "Ethanol from Corn" and "Ethanol from Sugarcane" pathways, respectively, listed in Table 6 of section 95486(b)(1).

A miscommunication between ARB, UC Berkeley, and Purdue resulted in a discrepancy between the emission factors discussed in the Staff Report (and presented on the ARB website) and the emission factors actually used in the land use change modeling for the regulation. The following statements were made in the Staff Report based on this miscommunication:

- "In applying the Woods Hole emission factors, ARB assumed that 90 percent of the above-ground and 25 percent of the below-ground carbon is emitted over the fuel production period (50-52)." (Page IV-21)
- "Our current modeling assumes 90 percent of the above ground carbon is released to the atmosphere following land conversion." (Page IV-46)

Instead of “90 percent,” the actual assumption was “100 percent.” Accordingly, the following corrections will be made in the Staff Report errata to reflect the actual assumption used in the modeling:

3. “In applying the Woods Hole emission factors, ARB assumed that 90 percent of the above-ground and 25 percent of the below-ground carbon is emitted over the fuel production period (50-52).”

will be changed to read:

“In applying the Woods Hole emission factors, ARB assumed that 100 percent of the above-ground and 25 percent of the below-ground carbon is emitted over the fuel production period (50-52).”

4. “Our current modeling assumes 90 percent of the above ground carbon is released to the atmosphere following land conversion.”

will be changed to read:

“Our current modeling assumes 100 percent of the above ground carbon is released to the atmosphere following land conversion.”

While the “90 percent” assumption is mistakenly shown in the Staff Report, the regulation approved by the Board with modifications actually incorporates a “100 percent” assumption. That is, the Board approved land-use change carbon-intensity values of 30 g CO₂/MJ for corn ethanol and 46 g CO₂/MJ for sugarcane ethanol, which are based on the assumption that 100 percent of the above-ground carbon is released to the atmosphere following land conversion and not 90 percent as stated in the Staff Report.

As stated in the Staff Report on page IV-46, we recognize the validity of the argument that when forests are converted to cropland, some of the above ground biomass will be converted to wood products, paper, and other consumer goods. The carbon in these items will continue to be stored while these products are used, and, in many cases, after they have been deposited in landfills. However, as also stated in the Staff Report on the same page, decay of biomass in landfills will more likely lead to release of methane (a more potent GHG) rather than carbon dioxide. This would have to be considered if a non-trivial percentage of biomass from converted lands is placed in landfills.

We also note that the emission factors used to calculate the carbon intensity of 28.3 g CO₂/MJ mentioned in the comment are incorrect. These emission factors assume 90 percent of above ground carbon from both forests and grasslands is released to the atmosphere following land conversion. It is not appropriate to assume 10 percent of grasslands biomass will end up in wood products, paper or other consumer goods and thereby not be released to the atmosphere.

The ARB staff continues to analyze this complex issue to determine the most appropriate percentage of above and below ground carbon that is released to the atmosphere. In recognition of the complexity of this and other issues relevant to land use change calculations, the Board directed the staff in Resolution 09-31 to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. The Executive Officer was directed to return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified through the Expert Workgroup.

IV-5. Comment: Based on the trends in land use change per capita, ARB should move forward the baseline year. For example, the baseline year could be set at 2007, during which time the annual ethanol production was ~6.5 billion gallons. According to the FAO statistics, these 6.5 billion gallons of ethanol fuel do not cause the global arable land expansion. (Note that 2007 ethanol production depends on 2005 or 2006 corn production.) This volume of ethanol does not produce indirect land use effects. There would need to be no conversion of forest or grassland to croplands in response to corn already diverted to ethanol production. Thus, only 8.5 billion gallons of ethanol among 15 billion gallons (56 percent) can conceivably be viewed as contributing to the hypothetical indirect land use effects, assuming one grants the theoretical and, to date, empirically unsupported premise that land use change is or will be caused by a decision to use U.S. biofuels. (GE4)

Response: The rationale behind the assertion that “ARB should move forward the baseline year” is not discernable in this comment. A response to that assertion, therefore, is not possible. We can, nonetheless, take a closer look at some of the information presented in this comment. The statement that the estimated 6.5 billion gallons of ethanol produced in 2007 do not cause land use change is completely groundless. The reasons are primarily twofold. First, the data on which this statement relies is *per capita* data. The per capita land use change rate, of course, masks the absolute rate of land use change. Per capita land use change could be falling while absolute land use change is increasing. This can happen because the denominator – world population – is steadily growing, while the numerator – hectares converted – also grows, but more slowly than the denominator. This results in a declining per capita rate superimposed over an increasing absolute rate. Secondly, even if the absolute rate of aggregate land use change is declining, the production of 6.5 billion gallons of corn ethanol will still stimulate land use change. Aggregate land use is driven by a number of factors. Some of those will exert downward pressure on the conversion rate while others will exert upward pressure. The net effect of all factors – the aggregate conversion rate – tells us nothing about the direction of each individual factor. Ethanol production could be exerting a strong upward pressure on the conversion rate, but still be counteracted by the factors acting in the opposite direction. Even if we remove the masking effect of a per capita rate, therefore, a declining absolute rate still does not indicate that ethanol production is not driving land use change.

IV-6. Comment: RFA believes that if ARB is intent on adopting an indirect carbon intensity value for ethanol as part of the Lookup Table, staff *must not* adopt the current 30 g/MJ estimate for corn ethanol because of an obvious technical oversight in the ISOR. This technical oversight involves ARB's failure to revise the 30 g/MJ estimate downward based on the inclusion of a carbon storage derating factor that acknowledges some of the above-ground carbon remains sequestered in wood products when a land use change occurs on forest land. The ISOR clearly states that ARB considered and included this factor, yet the change is not reflected in the 30 g/MJ ILUC estimate for corn ethanol. Therefore, we believe ARB must not adopt the 30 g/MJ figure until this error is corrected. (RFA3)

Response: See response to Comment IV-4.

IV-7. Comment: The GTAP model does not substitute DDGS for soybean meal. This can be remedied somewhat by increasing the elasticity of substitution among feedstuffs in GTAP, and when this is done even to a modest degree, the corn ethanol ILUC emissions value drops by 16 percent. (RFA3)

Response: Within GTAP, the substitution of DDGS for other animal feeds is dependant on relative prices of the feeds and the magnitudes of the elasticities of substitution between feed types. Elasticities of substitution reflect the relative ease with which different feed types will substitute for each other in different animal rations (e.g. dairy, other ruminants, and non-ruminants). In the modeling performed for the LCFS, ARB relied on the judgment of GTAP experts at Purdue to determine the most appropriate elasticity values for animal feed substitution. Including DDGS as an animal feed alternative in the GTAP model reduces the estimated land use change by approximately 40 percent, a result largely consistent with the displacement credit for DDGS used in the CA-GREET calculation of direct carbon intensity. The displacement credit used in CA-GREET is based on the assumption that 1 lb of DDGS replaces 1 lb of feed corn. Rationale for this assumption was presented in the co-product analysis included in Appendix C of the Staff Report and approved by the Board. However, recognizing the uncertainty in the land use change analysis and the more specific issue of co-product credits, the Board directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. Recommendations made by the Expert Workgroup on this issue will be seriously considered.

IV-8. Comment: Similarly, ARB must confront the practical limitations on the competitiveness of the corn ethanol industry in California, which are addressed in Appendix B of these comments, if the carbon intensity values in the ARB Lookup Table are finalized. Those limitations are important to any economic assessment of the proposed amendments to section 95486. They make it improbable that any firm seeking investment in corn ethanol production facilities to supply the

California market will be able to obtain the resources it would need to maintain a presence in that market. (GE4)

Response: The LCFS is designed to influence the market for California fuels—not by designating specific fuels that are favored and not favored, but by establishing declining annual carbon intensity limits. The regulation provides fuel suppliers with the flexibility to meet that standard with any mix of fuels they find to be advantageous. It is true, however, that fuels with higher life-cycle carbon intensities will likely be less favored by fuel suppliers, and may face a competitive disadvantage. Although some individual producers of higher-carbon fuels may experience declining sales, the Board has found that the regulation will not have a significant negative impact on the economy of California (see Chapter VIII of the ISOR). Moreover, the Board, responding to Executive Order S-01-07, has determined that market changes will be necessary to achieve the urgent overriding goal of reducing GHG emissions from California.

GTAP

IV-9. Comment: The 2006 Act also directs the Board to use only the “best available” scientific and economic information. As explained in detail in the accompanying materials, and based on earlier submissions to the Board by numerous parties, the application of the model structures provided by GTAP cannot be reconciled with the requirements of the 2006 Act and other applicable constraints on the Board’s rulemaking powers. The application of GTAP for the purpose of developing specific, fixed-point land-use penalties for biofuel usage does not comport with sound scientific methods, as noted by at least one of ARB’s peer reviewers and by several members of the peer review panel convened by the U.S. Environmental Protection Agency as part of the federal government’s efforts to implement the Energy Independence and Security Act of 2007. (GE4)

Comment: Equally important, and as noted earlier, the 2006 Act requires ARB to use “the best available” scientific and economic information in developing GHG regulations. The relevant scientific and economic information involved here includes predictive models like the GTAP modeling framework. A basic question in evaluating models is the reliability, and the quality of their inputs. Agencies are not permitted to rely on outdated inputs for models and on models shown to be unreliable. See, e.g., *Owner-Operator Independent Drivers Ass’n v. Fed. Motor Carrier Safety Admin.*, (D.C. Cir. 2007) 494 F.3d 188, 203-207; *Lands Council v. Powell*, 395 F.3d 1019, 1034 (9th Cir. 2005); *Appalachian Power Co. v. EPA*, 249 F.3d 1032, 10541-55 (D.C. Cir. 2001); *Columbia Falls Aluminum Co. v. EPA*, 139 F.3d 914, 922-223 (D.C. Cir. 1998). (GE4)

Comment: As explained in an accompanying Declaration prepared by one of the world’s foremost experts in the study of biofuels, the application of the GTAP models to the issue of indirect land use change fails to meet basic minimum requirements of the scientific method. See Dale Decl. ¶¶ 12-16. (GE4)

Comment: The application of the GTAP model structure to the issue of indirect land use change has also been challenged by other experts and researchers, outside of these proceedings. ARB is obligated to consider those challenges, which Growth Energy is now adding to the record here.

1. The analysis of GTAP by one participant in EPA's peer review process for the federal renewable fuels standards rulemaking was summarized as follows by EPA's contractor: [The EPA peer reviewer] enumerated several other weaknesses of general equilibrium models which make them unsuitable ... He commented that while general equilibrium models rely on production functions, the empirical basis for these production functions is "extremely weak." **As an example, he noted that when Purdue University economists were adjusting the GTAP model to calculate indirect land-use change for the California Air Resources Board, they forced the production functions to reproduce a yield/price elasticity in theory derived from econometric studies.** [The peer reviewer] noted that this elasticity may not be valid, and furthermore, that the overall elasticity does not define what variables to adjust to produce that elasticity. He concluded that, "because the relationship of the supply and price of these inputs to outputs is therefore based on limited empirical basis, it is not particularly helpful to vary those input supplies and prices in responses to general equilibrium features." [The EPA peer reviewer] also commented that the addition of general equilibrium interactions adds considerable uncertainty to the analysis by adding additional interactions and factors that are highly uncertain. He concluded that, "any theoretical gain in comprehensiveness is not worth the cost in uncertainty."

2. Another EPA peer reviewer, Dr. Michael Wang of the Argonne National Laboratory, termed the emissions coefficients used in models like the GTAP model "crude," see Exhibit F at E-2, and stated, "one may question the rationale of using economic modeling for developing regulation that is intended to promote technology innovations." *Id.* at E-8.

3. A third EPA peer reviewer stated as follows: I actually question the "openness" of the [GTAP] model. [Its] long history, complexity and the arcane nature of its development actually obscure its apparent transparency. Even more problematic for GTAP ... is the fact that it is a strictly an equilibrium model **that is incapable of properly capturing dynamic changes in the global ag sector.** This has forced the GTAP modelers to use awkward and questionable "fixes" to force their analysis to reflect future changes in agriculture that cannot be explicitly captured in a static model. Indeed most of these fixes must be done externally to the model. (GE4)

Comment: The use of the GTAP framework for purposes of predicting land-use changes does not meet any proper standard for regulatory proceedings as important as this rulemaking (See pp. 13-14 above.) The most that can properly be said with confidence is that the GTAP model was "available" to ARB; but that

type of availability does not meet the statutory criterion, which is to use the “best available economic and scientific information.” Health & Safety Code § 38652 (e) (emphasis added). ARB and the developers of the GTAP model that it sponsored appear to be alone in the view that GTAP is the “best” available method to estimate the complex series of decisions and events implicit in the ILUC theory that are relevant to what the 2006 Act calls “leakage.” There are other methods of predicting those decisions and events that show no significant indirect land-use change. ARB must explain why those other methods do not provide the “best available” approach to estimating leakage. (GE4)

Comment: Growth Energy is aware of no prior ARB rulemaking in which the Board has finalized a regulation based on a predictive model (or a predictive method) that has been questioned by one of its external peer reviewers; one of whose primary authors has conceded to use out-of-date inputs; and which has encountered such heavy criticism in a peer review process being conducted by ARB’s sister federal agency, EPA. If it decides to apply the GTAP framework in the final regulation, the Board needs to identify other rulemakings in which models or predictive methodologies that have been so sharply questioned have provided a basis for regulatory action. (GE4)

Response: The Board has found that the lifecycle and land use change analyses described in the ISOR do in fact constitute the best available scientific and economic information, and are fully reconcilable with the California Global Warming Solutions Act of 2006. This finding is based upon the following considerations:

- (1) The Board reached a specific finding that the staff appropriately included indirect land use change in its lifecycle assessment (Resolution 09-31, page 8).
- (2) The Board reached a specific finding that the carbon intensity values assigned to the various fuels, including the biofuels, are scientifically defensible (Resolution 09-31, page 8).
- (3) The ISOR was subjected to a peer review process. Of the four peer reviewers, one concluded that staff’s analysis of land use change was “state of the art” but subject to some improvement; another agreed with the staff’s contention that the land use change impact of biofuels was greater than zero, but felt staff’s estimates were uncertain and should be validated against empirical data; one did not comment except to say that staff’s estimates appeared to be too low; and one offered no comment, claiming no expertise.
- (4) The lifecycle analysis and land use change analyses performed on ethanol are supported by ample evidence. That evidence is discussed in detail in Chapter IV and Appendix C of the ISOR, as well as in the supporting fuel pathway documents found at <http://www.arb.ca.gov/fuels/lcfs/lcfs.htm>. The discussion of the lifecycle and land use change analyses performed on ethanol production were lengthy and comprehensive, comprising (relative to most other topics) a large proportion of the ISOR. All these documents are contained in the rulemaking record and were available for the legally required public review periods.

- (5) Even though the rulemaking record contains substantial evidence supporting the lifecycle analysis and land use change results for ethanol, the Board recognizes that the science underlying these analyses continues to evolve and to be refined. The Board therefore directed the Executive Officer in Resolution 09-31 to convene an expert panel specifically to evaluate advances in the science of land use change analysis (p. 15). The expert panel is to consider changes in agricultural yields, co-product credits, land emission factors, food price elasticity, and other factor that affect land use change estimation.
- (6) Finally, the LCFS regulation provides for two mandatory program reviews by the Executive Officer in 2012 and 2015 (see section 95489). One of the specific areas to be covered by these reviews is "advancements in full, fuel-lifecycle assessments," which, by definition, includes an assessment of methodological advances in the areas of lifecycle and land use change analyses, as these techniques are applied to the production of ethanol. Thus, the lifecycle and land use change analyses performed on ethanol are not only well-supported by the rulemaking record, but the Board's directives and the LCFS regulatory text ensure that continuing developments in the science of lifecycle analysis and land use change will be considered and incorporated into the LCFS program as necessary and as scientifically warranted.

Some of the more specific criticisms appearing in this series of comments are repeated in subsequent comments set forth below. More detailed discussions of those criticisms can be found in the responses to those subsequent comments

IV-10. Comment: The GTAP model applied in developing the LCFS regulation applies an economic theory that contains a complex series of interrelated postulates. The predictive accuracy or reliability of the GTAP model, as used for the current purpose in this proceeding, has not and cannot be tested. Some of it underlying assumptions are contradicted by currently available data. (GE4)

Comment: The peer review of the treatment of the indirect land-use issue by Dr. Valerie Thomas of the Georgia Institute of Technology also concluded that the application of GTAP in the LCFS rulemaking was deficient and did not reflect the use of the best available information (and thus, from a statutory perspective, did not comply with the 2006 Act). Dr. Thomas noted that the calculation of "indirect, land-use-change GHG emissions from production of corn-derived and cane-derived ethanol has significant uncertainties." She then goes further, however, and explains that "observed data" from the U.S. and Brazil "have not been used to validate the GTAP model findings" and that it would be feasible to adjust the model "to reflect [the omitted U.S. and Brazilian] data." Dr. Thomas also explains that ARB "could develop a more data-driven and less model-dependent approach" based in part on "land use patterns that have been observed to date." (GE4)

Comment: It is simply impossible, in light of Dr. Thomas' analysis, for ARB to conclude that the proposed use of GTAP reflects the "best available" economic

and scientific information. Even Dr. Hertel, one of the directors of the GTAP program, testified at the April 2009 hearing that GTAP's outputs were out of date, and suggested that the use of GTAP to predict dynamic outcomes would not be sound. It is therefore not surprising that other regulatory bodies have decided not to try to develop indirect land-use estimates for inclusion in current regulations, given the state of the science. (GE4)

Response: The ARB has acknowledged that land use change modeling does currently involve uncertainty. We also recognize that, in general, validation of computable general equilibrium (CGS) model results is difficult. The reason is that models of this type are meant to estimate the independent, incremental effect of a single causal factor. In the case of the GTAP analysis of the land use change associated with the production of corn ethanol, the incremental contribution of ethanol production to commodity prices, exports, land productivity, land use conversion, and other factors are estimated. Although data on commodity prices, exports, land conversion, caloric intake, trade volumes, etc. exist, they consist of aggregate numbers – they reflect the net effect of many, often competing factors. The individual effect of any one factor often cannot be teased out of them using empirical methods. The GTAP predicts that increased demand for ethanol will reduce corn and soybean exports, for example. The fact that aggregate corn and soybean exports actually rose over the period that was modeled is irrelevant. It just indicates that the factors tending to drive exports up (among them, rising meat consumption driving an increasing demand for livestock feed) tended to compensate for the downward pressure from the diversion of corn to ethanol production. Regardless of the actual aggregate trend in exports, it was lower than what it would have been in the absence of that diversion of the corn crop.

The commenters assert that some of the GTAP's "underlying assumptions" are contradicted by currently available data. The data to which they refer, however, is aggregate data – which, as shown in this response, is relevant to neither the model's assumptions nor its estimates. If data showing *only* the incremental influence of corn ethanol production on prices, exports, land use conversion, etc. were to be available, the Board would be keenly interested in seeing it. It is the unavailability of such data that makes the use of a predictive model like the GTAP necessary. Without such a model, the Board would have no way of gauging the incremental impact of corn ethanol production on land use change. Despite these difficulties, however, the GTAP, unlike most other CGE models, has been subjected to validation studies. The results of these studies have been used to improve and refine the model.

The use of a "more data-driven and less model-dependent approach" based in part on "land use patterns that have been observed to date" – although desirable – is also problematic. Neither the necessary data, nor the methods to analyze that data appear to be available at this time. Some of the difficulties associated with attempting to use actual land use change data for this purpose are very well described in comments received during the LCFS 45-day comment period. These comments make the case that the causes of actual land use change are often numerous, complex, and interrelated. In some cases, it is not even possible to identify all the reasons a given

tract was converted. In most, it is impossible to accurately weight all the causes behind a given conversion event. Some of those who submitted this comment cited a study appearing in *BioScience Magazine* (Helmut J. Geist and Eric F. Lambin, "Proximate Causes and Underlying Driving Forces of Tropical Deforestation," *BioScience Magazine*, Volume 52, No. 2 (Feb. 2002)) to support their arguments. The Board agrees that – for the reasons cited in these comments – estimating the indirect land use change impacts of fuel production from actual land conversion data is not currently possible. That is why it is necessary to estimate these impacts using a model that faithfully captures and quantifies the overriding economic forces that drive land use change.

The statements in these comments about Dr. Hertel's testimony at the April Board hearing are incorrect. First, Dr. Hertel did not state that the GTAP's *outputs* were out of date. He stated that the economic data on which the model is based – the primary model *input* – is out of date. He went on to explain that getting the global economic database that drives the model assembled, reviewed, and properly vetted is a time-consuming process. What is lost in terms of currency, however, is gained in terms of robustness of the model's outputs. Dr. Hertel's testimony began and ended with a discussion of why the GTAP database is its greatest strength. Moreover, some of the problems associated with an out-of-date database are correctable, according to Dr. Hertel, by the completely valid application of transparent and easy-to-understand adjustments. Secondly, Dr. Hertel did not suggest that "the use of GTAP to predict dynamic outcomes would not be sound." In discussing the pros and cons of using an older, but fundamentally sound database, Dr. Hertel mentioned that one alternative would be use the more complicated dynamic GTAP model to project forward to the desired future baseline date, and to begin the analysis at that point. He recommended against using this approach, since the likelihood that the future will unfold in keeping with the model's projections is completely unknown. Basing one's analysis on a projected future baseline only compounds the uncertainty faced by analysts using data from past periods. This can in no way be construed to suggest that using the GTAP to predict dynamic outcomes is not sound.

IV-11. Comment: While ARB has claimed that the version of GTAP applied in this rulemaking used 2001 as the "baseline" year, the documentation provided to describe the data base indicates that some of the data comes from the 1990s, and further that the operators of GTAP sometimes sought modifications in data and may have otherwise changed the data. (GE4)

Response: The economic database used for the LCFS GTAP runs is populated entirely with 2001 data. This database provides a robust snapshot of the world economy in 2001. The land use change emissions data, however, were collected during the 1990s. Although the economic database is updated at regular intervals, land use change emissions data is not. Land use change emissions databases were created as part of single, discrete research projects, and are not regularly updated. Unlike economic data, however, emissions factors are stable over time. The ARB has acknowledged, nonetheless, that GTAP land use change emissions estimates would be

improved by emissions factors that are specific to smaller geographic areas. The fundamental economic database on which the GTAP runs is assembled using a rigorous and lengthy process that includes exhaustive validation and thorough vetting. In the interest of providing users with the greatest possible flexibility, some GTAP data can be updated by the user. It becomes the responsibility of the user, then, to document and describe any data updates that were made, and the responsibility of peer reviewers to determine the validity of those alterations. To not permit updates would substantially restrict the usefulness of the model. However, the GTAP models incorporated by reference in the regulation are identified by a fixed date.

IV-12. Comment: Publications by the custodians of GTAP have made clear that the use of the data files in GTAP is expected to entail a great deal of judgment and ad hoc revision. While that candor is admirable, it raises serious questions about the utility of GTAP in a regulatory setting – according to those most knowledgeable about GTAP, it is at best “a useful starting point for forward-looking policy analysis.” This accounts in part for the concern about the use of GTAP for regulatory purposes in the scientific community. To date, it does not appear that ARB has taken full measure of those concerns and the basis for the concerns. (GE4)

Response: This comment is a fundamental misinterpretation of what the “custodians” of the GTAP model have stated. As pointed out in other responses in this section, the economic database on which the GTAP runs is assembled and implemented according to a time-consuming and extremely rigorous validation and vetting process. Dr. Hertel, who created the GTAP model, and who now oversees the organization that maintains it, has stated, quite correctly, that is a simple matter to chose model inputs (primarily elasticities) to achieve pre-conceived results rather than theoretically and empirically sound outcomes. In some cases, GTAP data can also be updated by the user. Rather than flaws, however, these user options are simply aspects of the model’s flexibility and ease of use. Nor is this condition unique to the GTAP. Any flexible, relatively easy-to-use model will be prone to this sort of unintended and unauthorized use. Rather than restrict the range of available inputs and lock users out all the data, the solution to this problem is to demand that all who disseminate GTAP modeling results reveal and thoroughly justify their choices of model inputs and their database updates. We note, as well, that the comment claiming that the model’s custodians characterize the GTAP as “at best ‘a useful starting point for forward-looking policy analyses’” distorts the custodians’ meaning and intent. What the source document identifies as a useful starting point for forward-looking policy analysis is a specialized, very specific application of the GTAP model. The phrase is not applied generally to all GTAP modeling. The specific application being described is not used in all GTAP-based studies. The LCFS land use change analysis is not a study of this type.

IV-13. Comment: In sum, these are among the basic issues and problems with the application of the GTAP models in determining a specific carbon intensity value for indirect land use changes:

- The emissions coefficients are “crude.” (See Exhibit F at E-2.)
- The model cannot accurately predict dynamic events. (See Exhibit F at C-7 and the testimony of Dr. Hertel cited in note 30 above.)
- The results of the model cannot be tested directly, and are inconsistent with observed data. (See Dale Decl. paragraphs 17-22.)
- The assembly of data is “arcane” and the data are out of date (see Dr. Hertel testimony cited in note 30 above; Dr. Thomas’ peer review; Exhibit F at 18; and Exhibit F at C-7.) (GE4)

Response:

1. *The emissions coefficients are “crude.” (See Exhibit F at E-2.)*

The Woods Hole Research Center emission factors were compiled so that projected future land use change would occur primarily in regions and in ecosystem types that experienced agricultural land use conversion during the 1990s. Projected land use change was allocated to these regions in proportion to the amount of change that each experienced during the 90s. This approach allows conversion projections to follow established historical patterns. To date, ARB has seen no compelling data indicating that future patterns are likely to depart significantly from observable historical trends. Data on historical land use conversion trends were compiled from a variety of region-specific sources – the Food and Agricultural Organization Forest Resources Assessment, for example. The Woods Hole data are grouped into ten regions. For use with the GTAP model, those data were recategorized into 18 agro-ecological zones. Within each zone, emission rates are reported by ecosystem type. For each ecosystem type in each region, emission factors (annual metric tons of carbon per hectare) are derived from the available empirical data. The regional emission factors used in the GTAP consist of the weighted average of all ecosystem types within each region. Land use change emissions are calculated by multiplying the number of hectares converted to agriculture in each agro-ecological zone by the corresponding emissions factor, and then summing over all converted land areas. The variance, or error, associated the Woods Hole emission factors is not reported in the literature describing the construction of those factors. Although it is based on the best currently available empirical data, emissions factors are averaged over extensive geographical areas. Emission factors specific to smaller geographic areas (and with known error rates) would be preferable. As improved factors meeting these requirements become available, the Board will base its land use change emissions estimates on those factors. The Board is convening an Expert Workgroup to consider possible approaches to improving its land use change estimates. Parties with potentially useful emission factor data should submit that information to the Expert Workgroup. In the meantime, the Board has adopted a conservative (low) land use change carbon intensity increment for ethanol from corn, pending the development of estimation methods that yield greater precision overall.

2. *The model cannot accurately predict dynamic events. (See Exhibit F at C-7 and the testimony of Dr. Hertel cited in note 30 above.)*

As noted in Comment IV-10, this comment mischaracterizes Dr. Hertel's testimony. Although Exhibit F at C-7 makes no mention of the GTAP's ability to predict dynamic events, this assertion does occur at two other locations in Growth Energy's comment packet (Appendix D at D-3, and Exhibit F at 4).

ARB chose the GTAP model (a computable general equilibrium or CGE model) for several reasons, which are briefly outlined in Chapter IV of the ISOR. As stated on page IV-46 of the ISOR:

The GTAP has a global scope, is publicly available, and has a long history of use in modeling complex international economic effects. Therefore, ARB staff determined that the GTAP is the most suitable model for estimating the land use change impacts of the crop based biofuels that will be regulated under the LCFS. The GTAP is relatively mature, having been frequently tested on large-scale economic and policy issues. It has been used to assess the impacts of a variety of international economic initiatives, dating back to the Uruguay and Doha Rounds of the World Trade Organization's General Agreement on Tariffs and Trade. More recently, it has been used to examine the expansion of the European Union, regional trade agreements, and multi-national climate change accords.

ARB acknowledges that static CGE models are limited by their reliance on static baseline parameters such as long-term crop yields (short-term, price-driven yield changes *are* accounted for using a yield elasticity parameter). The GTAP produces a single result based on a single changed condition (an increased demand for ethanol, for example), without respect for the time period over which the global economy returns to equilibrium following the introduction of the change. Equilibrium could return in less than a year, or over a period of several years. If the latter, it would be best if each year could be modeled individually (dynamically) using input parameters specific to that year. ARB discusses this limitation on page IV-46 of the ISOR:

GTAP uses the 2001 world economy as a baseline and does not account for changes that have occurred over the past eight years. The change that has the most significant effect on the land conversion estimate is the increase in crop yields since 2001. An increase in crop yields will lead to a corresponding decrease in land conversion. In response to this stakeholder concern, ARB staff and GTAP modelers have adjusted the land conversion estimate to account for the observed increase in crop yields. This adjustment was made to the model results rather than within the GTAP itself.

Stakeholders are correct in stating that a dynamic model could account for changes in technology, agricultural practices, population, etc, which occur over time. However, when land use change modeling was initiated for the LCFS, no dynamic model was

available that was comparable in quality to GTAP and adequately met ARB's criteria for selection (e.g. global scope, public availability, and history of use in modeling complex international economic effects).

At the April 23, 2009 hearing, the Board approved the use of GTAP to evaluate worldwide land use conversion associated with the production of crops for fuel production. The Board also acknowledged in Resolution 09-31 that the available methods for estimating indirect impacts (including land use change) are relatively new. In recognition of the relatively recent development of LUC analytics, the Board directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. ARB staff will seriously consider the findings of the workgroup in its continuing efforts to improve the LUC assessment. In approving the LCFS, however, the Board found that current uncertainty levels are not sufficient to call into question the existence of significant indirect land use change impacts.

3. *The results of the model cannot be tested directly, and are inconsistent with observed data. (See Dale Decl. ¶¶ 17-22.)*

See the response to Comment IV-10, above.

4. *The assembly of data is "arcane" and the data are out of date (see Dr. Hertel testimony cited in note 30 above; Dr. Thomas' peer review; Exhibit F at 18; and Exhibit F at C-7.)*
5. For the Board's response to the comment about Dr. Hertel's testimony, please see Comment IV-10, above. John Sheehan is quoted in this comment letter as stating that the GTAP's "long history, complexity and the arcane nature of its development actually obscure its apparent transparency." We note that we did not find in the comment document any statements to the effect that the "assembly of data" is arcane. As such, we will respond to Mr. Sheehan's charge. The GTAP is a computable general equilibrium model of the *global* economy. The database on which the model operates consists of input-output tables (or 'social accounting matrices') representing 111 world regions, and 57 economic sectors. These tables capture economic relationships within each region, as well as trade relations between regions. The land use module contains data on 18 global agro-economic zones. The economic data is assembled in a ground up fashion from more than 6,500 people representing more than 100 countries. Once assembled, the data is subjected to rigorous validation and vetting. The model operates by mathematically calculating a new global economic equilibrium following the introduction of an event, which creates a state of disequilibrium. This calculation – though mathematically sophisticated – is based upon input-output modeling techniques that have been in regular use for many years. It would, however, be unreasonable to expect a model this large and this capable to be fully accessible, transparent, and simple – especially to a non-economist. Despite its size and sophistication, the model is packaged in a portable form and

is available to anyone who would like to purchase it. It can be installed and run on most standard Microsoft Windows-based computers in common use today. Although the model is large and sophisticated, it is based on a standard economic analytical approach and is portable and available. Given these characteristics, the Board feels that referring to the GTAP as “arcane” is inappropriate and misleading.

IV-14. Comment: Statistics from the United Nations Food and Agriculture Organization (the “FAO”) show that global arable land increased by 23 million hectare from 2001 to 2007, and 78 million hectare of land accounted for as “other land” also increased over that time frame, while about 103 million hectare of forest and pasture has been converted since 2001. About 54 percent of newly converted arable land is from forest. On a worldwide basis, ARB is not justified in claiming more than 54 percent forest conversion in its calculations, based on past evidence, if one assumes that there is any validity to the ILUC theory. (GE4)

Response: The Board’s analysis indicated that, globally, an estimated 3.89 million hectares would be converted to farmland in response to a 13.25 billion gallon per year increase in the production of corn ethanol in the U.S. 3.89 million hectares is 16.9 percent of the 23 million hectare figure cited in this comment. The proportion of forest converted in the Board’s analysis could have been well above 54 percent without in any way conflicting with the aggregate FAO figures in this comment. The 54 percent barrier the commenters attempt to erect is completely illusory.

As it happens, however, the percentage forest converted under ARB’s corn ethanol scenarios does not exceed 34 percent. The corresponding conversion rate under the Board’s sugarcane ethanol scenarios does not exceed 43 percent.

IV-15. Comment: Pasture and grassland incur relatively small carbon debts upon conversion to arable land (Kim, Kim and Dale, 2009 and Fargione, et al, 2008, attached hereto as Exhibit M) even under the worst management post land use change. In Africa and the Americas, forest was the only land source for newly converted arable land, while pasture was the only source of new arable land in Asia. (See Table 1 below, which is based on FAO data.) As noted in Dr. Dale’s Declaration, the work of Dr. Robert Brown shows no effect of either soybean prices or commodity food prices on deforestation rates in the Amazon, thereby further undercutting ARB’s argument of the link between rising commodity agricultural prices and tropical deforestation. (GE4)

Response: See the response to Comment IV-5, above. As that response indicates, the lack of a statistical relationship between American commodity prices and deforestation is (a) entirely expected, and (b) in no way an indication of a flaw in the Board’s land use change analysis. Among the many reasons that Dr. Brown’s test has no applicability to the Board’s land use change modeling is that Amazonian deforestation is driven by a number of factors. The price effects of the diversion of a portion of the American corn crop to ethanol production is but one of those factors. The

aggregate deforestation rate represents the net result of all factors – some of which will act to accelerate, others to decelerate, the aggregate rate. Dr. Brown’s simplistic test is built upon the unspoken assumption that the price effects used as independent variables would be the only, or perhaps, the primary drivers of Amazonian deforestation. In reality, those price effects are assuredly not the only, and almost certainly not the primary drivers. As such, Dr. Brown’s model is woefully misspecified. Unless he is able to identify all, or at least most of the factors responsible for deforestation, and collect appropriate data sets on those factors, he cannot begin to create a model able to produce the results he is looking for. There is an additional complication as well: there is a lag between changes to most drivers of deforestation and the actual felling of trees in response to those changes. This is certainly true of the price effects in his current model. He would have to properly specify and model those lag periods. Obviously, a model of this type would be extremely difficult – if not impossible – to construct. If one that had been tested, calibrated, peer-reviewed, and published were indeed available, there would be no need for the Board to use a predictive model to estimate land use change impacts. It is precisely the lack of such a model that makes the use of a predictive model such as the GTAP necessary.

IV-16. Comment: In another deviation from the “best available” information, ARB does not follow the 2006 Intergovernmental Panel on Climate Change (“IPCC”) guidelines in their calculations of soil carbon loss. Furthermore, carbon losses from changes in soil depend significantly on the time period after conversion as well as post conversion management practices. ARB arbitrarily chooses a 30 year period, but IPCC uses a much longer time period of 80 years. The data from Follett *et al.* (2009) support the use of no-till farming practices as a method of conserving the SOC that was sequestered during the time period that the land was in the CRP. This implies that cropping management can increase soil organic carbon levels in converted croplands. ARB ignores the effect of crop management on soil carbon. (GE4)

The proposed LCFS regulation uses a 30-year project horizon. Indirect land-use change emissions are divided by 30 years and assigned to ethanol. Even though the LCFS program may cease at the end of project horizon, the effects, particularly indirect effects, last much longer than the project horizon. This is the same reason that an 80- to 100-year time horizon for global warming potentials is widely used. There is no intellectually valid reason for ARB to use a much shorter period for analysis. According to ARB’s assumptions, after that period, these converted croplands disappear or become environmentally inert. That is implausible. (GE4)

Comment: In addition, the ARB analysis does not specify the fate of converted croplands after 30 years. There are two scenarios for the use of converted croplands after 30 years: (i) after 30 years, converted croplands will be continuously used as croplands; or (ii) converted croplands will be re-converted back to grasslands or forest because we will not need these croplands any more at that time. For scenario (i), the initial land-use change emissions due to

removing aboveground biomass should be distributed to the time period for croplands (divided by how many year croplands are used). For scenario (ii), carbon sequestration in re-converted natural lands should be taken into account. To understand the significance of this point, it may be hypothesized that the impact period for converted croplands is 80 years, and that the converted croplands will be continuously used as croplands. In this case, the indirect land-use change carbon intensity for 80 years is $(897.7 + 4.1 \times 50) / 80 = 13.8$ (g CO₂/MJ). On that basis, a value of 13.8 gCO₂e/MJ would become the value for converted croplands. That is a far more defensible outcome, if one initially assumes that the indirect land-use change concept is to be given any scientific credibility. (GE4)

Response: The Woods Hole Research Institute emission factors used in the GTAP model have a significant advantage over the corresponding IPCC emission factors: The Woods Hole factors are location specific. They are provided for the forests and grasslands within each of ten world regions. In other words, they are region- and cover-type-specific. The IPCC factors, on the other hand, are global values. No geographical distribution is given. Another difference between the IPCC and Woods Hole emission factors is that the latter are significantly higher than those from Woods Hole. Had the GTAP model used the IPCC factors, all of the Board's land use change carbon intensity estimates would have been considerably higher.

The carbon intensity of crop-based biofuels is highly sensitive to the project horizon chosen to annualize emissions as detailed in Appendix C of the ISOR (C-21). However, the choice of thirty years is not arbitrary. As stated in the ISOR (IV-23), the value chosen for the project horizon is very important as it determines how long a fuel has to "pay back" the land use change emissions that it generates. For a crop-based biofuel, GHG costs and benefits accrue at very different rates through time with large up-front costs and comparatively low annual benefits. The longer the project horizon, the more time the annual benefits are given to catch up with the large up-front costs. A short project horizon (e.g. less than 20 years) favors fuels that have low up-front land use change costs while a long project horizon (e.g. greater than 50 years) deemphasizes up-front land use change emissions and favors fuels that have large annual benefits.

A relatively short project horizon is warranted for at least two reasons. First, the scientific community is warning that very significant reductions in GHG emissions are needed in the near term to diminish the potential for large and possibly irreversible damage from climate change. Achieving these reductions requires approaches, which promote fuels that provide earlier benefits. Second, it is very difficult to project the mix of fuels and production methods over the next three decades, much less through the remainder of the century. The assumption that the production techniques used for fuels supplied to meet the LCFS will continue for many decades to come is very uncertain. Requiring a shorter "payback" period is far more likely to produce net benefits. For these reasons, a long (e.g. 100 year) project horizon is not appropriate.

The ARB adopted 30 years as a compromise, which allows for crop-based biofuels that employ the most efficient production methods to play a role in meeting the goals of the LCFS but also promotes the transition to truly sustainable fuels that provide substantial near term as well as long-term emissions reductions. As structured, the LCFS provides strong incentive to both improve the GHG performance of current biofuels as well as encourage investment in 2nd and 3rd generation fuels.

As discussed in the ISOR, ARB acknowledges that for crop-based biofuels some reversion of land may occur after the fuel no longer receives LCFS credits. Moreover, a scenario showing the sensitivity of land use change carbon intensity to the inclusion of land reversion is presented in Appendix C of the ISOR (C-18). We concluded that land reversion is highly speculative and if it does occur, the extent and duration are impossible to predict. Therefore, ARB took the cautionary approach of assuming that no land reversion occurs.

An overriding principle in ARB's land use change analysis is that past practices and trends best predict future practices and trends. For this reason, the analysis assumed no significant increase in advanced crop-management practices such as no-till cultivation. One reason to doubt that such practices would play a significant role during a period when ethanol production increases is that increasing commodity prices generally tend to encourage more intensive agricultural practices. The tendency will be to increase yields of the more profitable commodity rather than to preserve soils through no-till cultivation, full corn-soybean rotations, etc. If solid evidence becomes available indicating that significant numbers of farms are being converted to advanced tillage regimes, ARB will consider modifying its land use change analysis accordingly.

IV-17. Comment: Carbon releases due to changes in soil organic carbon levels after land conversion depend on both the land conversion process and crop management in converted croplands. Crop management in converted croplands is almost totally associated with animal feed production, and not with ethanol production system. Therefore, these carbon emissions due to changes in soil organic carbon levels should be assigned to *both* biofuel and animal feed production in converted croplands, to the extent that indirect effects are to be considered. (GE4)

Response: This comment seems to be based on a fundamental misunderstanding of the land use change process modeled in our GTAP analysis. The emissions from *all* categories of land use change stimulated by an increase in ethanol production are summed, and then converted to energy-based units.

IV-18. Comment: In the ISOR, ARB established 0.4 as its Corn Yield Elasticity factor for use in the GTAP model based on historical literature reviews for the U.S. The reasoning and analysis that lead ARB to assume that such a factor should apply internationally is not presented. A working paper written by Keeney and Hertel documents a range of values for corn yield elasticity with values as high as 0.76

historically. ARB must explain why it did not apply the values in the working paper by Keeny and Hertel. (GE4)

Response: Staff worked together with Professor Hertel and he recommended the range of values for the crop yield elasticity for corn that were presented in the Staff Report and presented to the Board for approval. The range of values was based on historical literature reviews as recommended by Professor Hertel. The land use change carbon intensity of corn ethanol is at a very reasonable level, pending further examination by the Expert Workgroup to be convened in response to Board directives contained in Resolution 09-31. Staff's current assessment is that there are at least as many adjustments that would raise land use change carbon intensity, as there are adjustments that would reduce it.

IV-19. Comment: It is also questionable for ARB to assume that a fixed Corn Yield Elasticity factor applies internationally. ARB should consider using elasticities for each crop or each AEZ in each country not just one value for all. The current method has not been demonstrated as the best science available. In the GTAP working paper *Global Land Use and Greenhouse Gas Emissions Impacts of U.S. Maize Ethanol: the Role of Market-Mediated Responses*, Hertel et al use a value of 0.66 for elasticity of crop yields with respect to area expansion as a central value, yet for ARB's GTAP analysis the ISOR indicates a value of 0.5 was selected. (GE4)

Response: See response to previous comment.

IV-20. Comment: The treatment of yield on new cropland. Until the Expert Workgroup completes its analysis, ARB should increase their "new" crop land elasticity assumptions to reflect actual data on yields in areas where this land use change is expected to occur. (ILCORN2)

Response: Staff has carefully considered the information stakeholders submitted concerning the sources of uncertainty in LCFS land use change estimates. When that information was found to have merit, staff revised its analysis to reflect the issues raised. For example, the elasticity of crop yields with respect to area expansion was increased based on information from stakeholders (this elasticity quantifies the productivity of converted lands relative to existing cropland); the revisions reduced current land use change carbon intensity values. Given the adjustments, the land use change carbon intensity of corn ethanol is at a very reasonable level, pending further examination by the Expert Workgroup to be convened in response to Board directives contained in Resolution 09-31. Staff's current assessment is that there are at least as many adjustments that would raise land use change carbon intensity, as there are adjustments that would reduce it.

IV-21. Comment: The treatment of US versus ROW crop yield growth rates: ARB's assumption that US and ROW crop yield growth rates are the same is not an accurate assumption as demonstrated by looking at available historic data for the

period of time since ARB's selected base year of 2001. This implies that ARB's exogenous yield adjustment has overestimated land use change emissions. (ILCORN2)

Response: The external adjustment performed on the GTAP model captured the increases in yields for crops that happened up to 2008. We did assume that the yield growth adjustment for the US and the ROW were the same. If we are presented with data that this assumption is significantly in error, we will modify the external adjustment. The mandatory program review in 2011 and 2014 can be used to facilitate this revision.

IV-22. Comment: RFA and other stakeholders have repeatedly raised concerns about the exclusion of certain land types in the GTAP land database. This problem was identified early in the stakeholder process. Specifically, Conservation Reserve Program (CRP) lands, idle cropland, and cropland/pasture are excluded from the GTAP model's database. This is particularly problematic because these lands would most likely be the first to be converted to crops if expansion of biofuels production necessitated land conversion. Because these excluded lands are predominantly grassland or pasture, the carbon emissions from conversion would be much lower than those associated with conversion of forest. On numerous occasions, we have raised this concern with ARB staff and asked that these lands be added to the GTAP database. ARB staff acknowledged in the summer of 2008 that this was a potentially significant omission and pledged to examine the effect of including these lands. Yet, these lands were never added to the database and the ISOR states, "ARB staff and GTAP modelers are updating GTAP to include Conservation Reserve Program land, as appropriate. We will then analyze the effect that this change has on the estimate for amount and location of land converted within the U.S." We believe adding these lands to the database will have a significant effect on the overall ILUC value. ARB has provided no explanation for failing to add these lands to the database and cannot finalize the rule without providing some explanation and analyzing the effect of doing so. Because ARB staff has provided no rational basis for excluding these lands in the GTAP database, the rule appears arbitrary and lacks evidentiary support for the ILUC values derived for corn ethanol. Prior to sending this rule to OAL, ARB should update the GTAP land database, perform new model runs based on the inclusion of these lands, and make corresponding adjustments to ILUC values. (RFA3)

Response: The Board acknowledged in Resolution 09-31 that the available methods for estimating indirect impacts including land use are challenging. The adopted regulation was developed using the best available economic and scientific information. We agree that there needs to be further work to characterize in greater detail of the land use types that are subject to conversion by the GTAP model, such as CRP land, idle and fallow cropland. One can generally refer to these as surplus croplands. There are efforts currently by many institutions and GTAP researchers to include these types of lands into the GTAP database. Once they become available, we will include them in

our GTAP modeling. However, their absence at this time does not render the regulation arbitrary or lacking evidentiary support.

IV-23. Comment: During a discussion with ARB staff and Prof. Tom Hertel of Purdue on April 16, 2009, RFA staff, consultants and economists from Informa Economics presented information showing that one of the key GTAP elasticities has a significant effect on overall calculated land use changes. This elasticity is known as the “crop productivity elasticity with respect to area expansion” (hereafter referred to as the “expansion elasticity”). The information presented by Informa showed the real-world crop yield response on newly converted lands in areas where agricultural land use has recently expanded is significantly higher than currently assumed by ARB in GTAP modeling for corn (and other ethanol feedstocks). Prof. Hertel acknowledged that the Informa data and analysis were valuable. Prof. Hertel also acknowledged receiving feedback from other parties on another GTAP elasticity – the “price-yield elasticity.” He suggested that the model inputs be changed such that the expansion elasticity could be set as close to 1.0 as possible and the price-yield elasticity could be as close to zero as possible. The current expansion elasticity range being used by ARB is 0.5 to 0.75 (mean of 0.59) and the current price-yield elasticity is 0.25 to 0.4. Prof. Hertel indicated that updating these values would better represent the available data, and furthermore would better reflect traditional lifecycle analysis practices. RFA ran the GTAP model after changing these two elasticity values to the levels suggested by Prof. Hertel. The results show a corn ethanol ILUC value of between 15.7 and 17.1 g/MJ, as opposed to 30 g/MJ from the current ARB analysis. These results were shared with Ms. Nichols and other state officials in a memorandum dated April 23 from AIR. To date, ARB has disregarded this data and has provided no explanation for why it is not adopting the recommended approach. As such, the rule appears arbitrary and lacks evidentiary support. The two elasticity values should be revised as discussed with ARB staff. (RFA3)

Response: The GTAP modeling results for corn ethanol land use change as reported on Table IV-10 on page IV-31 of the Staff Report present 7 scenarios. As shown on the table, input elasticities values varied for each scenario and the results obtained from the most improbable combinations of input elasticity values were removed and the “most reasonable” ranges for elasticity values remained. The land use change carbon intensity value of 30 g/MJ is the average value of the 7 scenarios. By considering this extreme case as likely scenario, it would not result in a corn ethanol ILUC value to drop to 15.7 or 17.1 g/MJ. Adding that extreme value to the other scenarios in the Staff Report and averaging would more likely bring in a value of around 28-29 g/MJ for corn ethanol ILUC – not much different than what is in the Staff Report. Staff had received additional comments that assert ARB’s carbon intensity value of 30 g/MJ is low. The Board considered all comments before approving the LCFS regulation.

We acknowledge that the sensitivity analyses performed on its GTAP model runs were abbreviated. Although the total number of sensitivity runs performed exceeded the

numbers cited in this comment (only the runs based on the most reasonable elasticity values were discussed in the ISOR), formal sensitivity analyses leading to probability and uncertainty distributions were not performed. These were not possible given the time and resource constraints under which the LCFS land use change team worked. In recognition of this and other sources of uncertainty, ARB adopted a conservative (low) land use change carbon intensity increment for corn ethanol. Resolution 09-31 directs staff to form an Expert Workgroup to continue studying the land use change phenomenon, and the available approaches to measuring it. We expect this Workgroup will take up the issues of sensitivity and uncertainty analysis.

IV-24. Comment: The treatment of crop yield growth rates – domestic: Until the Expert Panel work is complete, ARB should, at a minimum, utilize USDA projected yields. Alternatively, they should treat yield as a time-dependent variable, similar to the way emissions due to indirect land use are treated as Edgerton suggested in his previous comments to ARB. (ILCORN2)

Response: The external adjustment performed on the GTAP captured the increases in yields for crops that happened up to 2008, i.e., current technology. Future yield projections as requested by the commenter were not included because it is not possible to forecast future yield growth rates. Furthermore, to treat yield as a time-dependent variable is to include the yet unproven technologies to adjust yield increases. The external adjustment used has made the indirect land use impact portion consistent with the GREET modeling portion that estimates the direct effects of land use impacts. In the GREET modeling, the projected carbon intensity values were given for the current technology as of 2008. With that in mind, staff recommended and the Board approved the method of combining the two direct and indirect effects from the current 2008 data.

IV-25. Comment: Growth Energy believes that the theory of indirect land use change relied upon in the ARB Lookup Table, and as implemented using GTAP, will send signals to the downstream regulated market with unintended economic consequences for the U.S. biofuels industry in general, and for the California corn ethanol industry in particular. The loss of the California market for U.S. corn ethanol will set back national efforts to launch cellulosic ethanol, because many of the most advanced corn ethanol biorefineries are intended to transition to cellulosic ethanol production. If those facilities cannot be maintained for the present as successful corn ethanol biorefineries, they will not be available for the launch of cellulosic ethanol. (GE4)

Comment: The combination of the ILUC penalty assigned to California corn ethanol pathways, the need to rely on corn transported from the Midwest, and the new competitive advantage granted to cane ethanol make the corn ethanol industry in California nonviable at the scale assumed by ARB in the ISOR, and probably non-viable at any scale. Removal of the ILUC penalty is essential to restoring the competitive position of the California corn ethanol industry. (GE4)

Comment: If adopted in its currently proposed form, the carbon intensity values in the ARB Lookup Table would eliminate some of the most important and environmentally progressive Midwest corn pathways from the California market by 2014. Because the California corn ethanol industry is already economically fragile, and is itself unlikely to be competitive in light of the new cane ethanol pathways, the LCFS regulation will enormously hinder the entire U.S. ethanol industry in the international competition to commercialize cellulosic ethanol. Those consequences appear to have been unintended, but they are nonetheless real. (GE4)

Comment: In comparing the results that would follow from implementation of the ARB Lookup Table in section 95486 with national biofuel policies, we believe that the State has given too little attention, if any, to the public interest in ensuring the vitality of the ethanol industry both inside and outside California. The assumptions made by the Board about the ability of the corn ethanol industry in California to revive itself and prosper under the new regulation are completely unrealistic. For corn ethanol producers located in the Midwest, the indirect land-use penalties in the ARB Lookup Table will force an exit from the country's largest single state ethanol market. This will have a huge impact on earnings and make it very difficult for ethanol producers to obtain the resources needed to lead the nation to ethanol produced from feedstocks other than starch, which is a top priority of the federal government and a goal that Growth Energy and its members are determined to achieve. (GE4)

Response: The California LCFS does not affect the volumes of corn ethanol, biodiesel, cellulosic and other advanced biofuels mandated under the federal Renewable Fuels Standard. The Renewable Fuel Standard volume mandates guarantee market security for these biofuels in aggregate. That is, additional volumes of advanced biofuels can be credited towards corn to ethanol volumes. The California LCFS only provides an additional incentive to produce biofuels for the California market with the lowest possible carbon intensity.

The LCFS is strictly a performance-based regulation. It sets fuel performance standards and calculates fuel carbon intensities, but lets fuel providers decide how best to come into compliance. Page VI-4 of the ISOR states:

The LCFS does not specify which combination of fuels the regulated parties must provide to comply with the standards. Instead, the LCFS requires producers and importers of transportation fuels to meet an overall carbon intensity for the fuel mix they supply to California. Regulated entities may meet the LCFS by using a combination of fuel blends, alternative fuels, and LCFS credits. Based on current and developing fuel and vehicle technologies, feedstock availabilities, and other factors, ARB staff in the ISOR has analyzed a number of possible compliance scenarios.

In the ISOR analysis, staff presents seven possible compliance scenarios – four for gasoline and its substitute fuels and three for diesel fuel and its substitute fuels. Each of these scenarios includes a mix of fuels that satisfy the LCFS. The purpose of describing compliance scenarios at this time is to demonstrate how the draft carbon intensity reductions are achievable, given prevailing and foreseeable future conditions. The compliance scenarios are not intended to predict or forecast the actual combination of fuels and vehicles that will be used.

The amount of corn ethanol – either California, or Midwest – used in generating the compliance scenarios presented in the ISOR is irrelevant to the ultimate success or failure of the low carbon fuel standard. Furthermore, assuring the competitive position of one or more classes of fuels is not among the objectives of the LCFS.

Regarding the assertion that, by rendering corn ethanol uncompetitive, the LCFS hinders and delays the development of more advanced fuels such as cellulosic ethanol, we foresee a continuing, though declining role for corn ethanol under the LCFS. If some of the more advanced corn ethanol plants are poised to pioneer cellulosic ethanol production (or the production of other next generation fuels), the Board has provided a few years for that transition to occur. It has, in fact, created incentives, in the form of credits, to hasten that transition. This incentive will also serve to expedite development of advanced fuels from firms other than ethanol producers. The extent to which the Board seeks to incent the development of such fuels is shown by its publication of a table of feedstocks expected to have little or no land use change impacts. This table will be included in a document entitled, “Establishing New Fuel Pathways Under the Low Carbon Fuel Standard: Procedures and Guidelines for Regulated Parties,” a draft of which is posted to http://www.arb.ca.gov/fuels/lcfs/fuels_pw_guidance.pdf. Examples of the feedstocks in this table are municipal and agricultural waste streams, cellulosic crops grown on marginal lands that could not support food, feed, or fiber crops, wastes from standard forestry practices (thinning, fire prevention, etc.), and cellulosic crops grown between existing row crops, or added to existing crop rotations. We want to clearly differentiate these feedstocks from others, like corn, soybeans, and sugarcane, which are known to displace food, feed, and fiber crops. This clear differentiation should dispel most or all of the uncertainty in the investment community about the anticipated role of next-generation biofuels under the LCFS.

IV-26. Comment: The competitive effects of the carbon intensity values in the ARB Lookup Table come into even clearer focus when one considers the advantage that the new cane ethanol pathways would give to Brazilian suppliers and other firms manufacturing ethanol from sugarcane. The LCFS regulation permits the downstream regulated parties to use multi-year credit trading to meet the standards applicable from 2011 to 2020. As the ISOR explains, the standards “are backloaded so that, if necessary, credits that were banked in the early years [of the regulatory program] will help with compliance in the later years.” See ISOR at V-22. A downstream regulated party could rely solely on the new cane ethanol pathways, starting in 2011, and demonstrate compliance with the LCFS regulation until 2020. The use of corn ethanol to comply with the LCFS

requirements is even more improbable if downstream gasoline refiners can obtain some reductions in their direct GHG emissions carbon intensity values under Method 2, or participate in programs that rely to some extent on the electricity pathways. (GE4)

Comment: The new carbon intensity values for at least one of the additional cane ethanol pathways in section 95486 do not reflect a full consideration of all GHG (“GHG”) emissions that should be attributed to that pathway. The compliance analyses in Appendix E of the initial regulatory support materials have not been updated to reflect the new and much lower carbon intensity values assigned to imported ethanol, and it is not apparent why the staff has not done so. It is improper to provide any preference, substantive or procedural, to the suppliers of one type of low-carbon fuel in the current post-hearing process. The new carbon intensity values for imported ethanol should be removed from the regulatory proposal. The proponents of those new values can follow the procedures prescribed for the certification of new pathway values in Method 2 of proposed section 95486, once that Method is fully defined, on the same basis as any other ethanol supplier. (GE4)

Response: The Board, in approving the regulation, directed staff to analyze and publish carbon intensity for two additional pathways for sugarcane ethanol. In preparing these pathways, staff observed all applicable requirements of the California Administrative Procedures Act. The analysis was published for comment, and, based on the comments received, appropriate refinements were performed. A 30-day comment period – longer than is statutorily required – was even provided for the public review of staff’s analysis. Regarding the potential for suppliers to use sugarcane ethanol to achieve full compliance in the early years of the regulation (by banking credits), we respond as follows:

- (1) Sugarcane ethanol from Brazil currently faces significant trade barriers in the U.S. We do not project those barriers to be lowered while the LCFS is in effect.
- (2) If the trade barriers preventing sugarcane ethanol into the American market were to be removed, or other changes were to occur which allowed suppliers to bank enough credits to achieve early compliance, the Board will reassess its current compliance targets and schedules, and make adjustments as deemed necessary. Two opportunities to accomplish such a program review are currently built into the regulation – the Executive Officer is required to formally review the LCFS in 2011 and 2014 (see Section 95489 of the LCFS Regulation)

IV-27. Comment: For all that appears in the current record, the Board has conducted no analysis of the economic impact of the LCFS regulation in general, or the “signals” provided by the Lookup Table, on the corn ethanol industry outside California. The regulation will impose significant financial harm on those out-of-State suppliers (see Appendix A), and will set back the national effort to improve employment conditions and income in the Farm Belt and in other rural areas of

the nation. If the Board considers such out-of-state impacts to be outside the scope of this rulemaking, or subordinate to other interests, then it should so state, and explain why. For its part, Growth Energy respectfully submits that the Board is obligated to consider and then explain the impacts of the LCFS regulation not only on California consumers and businesses, but on out of-state corn ethanol suppliers. (GE4)

Comment: The independent research firm ProExporter Network (“PRX”) regularly publishes reports on the impact of regulations on market conditions in the ethanol industry. A report by PRX dated August 10, 2009, and attached to these comments with the permission of PRX as Exhibit D, demonstrates that the carbon intensity values in the Lookup Table will cause some Midwest corn ethanol pathways to become non-viable as part of an LCFS compliance strategy as early as 2014. The Midwest corn ethanol pathways that provide dry distiller’s grains with solubles (“DDGS”) products are particularly disfavored, despite the significant agricultural conservation benefits of DDGS – benefits that, Growth Energy respectfully submits, have been underestimated in ARB’s analysis. The Midwest corn ethanol pathways in general, and the facilities producing DDGS in particular, cannot compete under the LCFS framework owing to the inclusion of the ILUC penalties in the Lookup Table. (GE4)

Response: See the responses to Comments IV-19 through IV-22, above for a discussion of the Board’s assessment of the impacts of the LCFS on the California and Midwest ethanol industries. To summarize, we anticipate those impacts to be minimal for three reasons:

- a. The volumetric requirements in the Federal Renewable Fuel Standard assure corn ethanol a market into the future;
- b. The LCFS is structure to provide corn ethanol producers with a transition period in which to develop lower carbon fuels to market; and
- c. The credits available to fuel providers under the LCFS create a strong incentive for the development of lower carbon fuels.

It is also true that production of DDGS is less beneficial, in terms of carbon-intensity determination, than wet distillers’ grains. The commenter asserts that the Board has underestimated the benefits of DDGS in its carbon intensity calculations, but does not discuss the basis of that assertion. Staff’s position is discussed in the ISOR. Also, see responses to Comments K-65, K-77, K-78 and K-82.

IV-28. Comment: I am writing because Eureka is troubled by the ILUC aspects of the proposal, and the effects the ILUC will have on my business, and the livelihoods of my customers. As a supplier of corn seeds to farmers throughout the San Joaquin Valley, Eureka is concerned about the unintended consequences the ILUC will have on California corn growers, corn seed suppliers, and other segments of the agricultural industry. The LCFS would discriminate against No. 2 corn, making California corn growers responsible for the economic decisions made in other countries over which our industry has no control. It

removes all incentive for farmers to stay or enter into the California corn industry by making it too difficult for California farmers to compete. The LCFS would also have other unintended consequences such as reducing crop diversity and balance in the San Joaquin Valley by forcing growers to move toward similar crops, such as alfalfa, leading to decreases in prices for those crops. (EUREKA)

Response: Chapter VI of the ISOR contains four illustrative “compliance scenarios” for gasoline and fuels that substitute for gasoline. These scenarios cover the LCFS compliance period of 2010 through 2020. All call for decreasing volumes of Midwestern corn ethanol, along with a constant 300 million gallons-per-year of low-carbon-intensity California corn ethanol. Almost all of this ethanol, regardless of where it is produced, is made from Midwestern corn. These scenarios reflect ARB’s understanding that very little California-grown corn is currently, or will in the future, be used for ethanol production. Most California corn is used for (and is expect to continue being used for) livestock feed. We therefore foresee no significant impacts of the LCFS on California corn growers, or San Joaquin Valley agriculture in general.

IV-29. Comment: Analysis of Biofuels Indirect Land Use Effects Finds the Science Lacking Too Diffuse and Subject To Too Many Arbitrary Assumptions To Be Useful for Rule-making.

- Lack of transparency and scientific integrity in Searchinger et al. questioned;
- Searchinger et al. paper described as more ideology than science and seeking to put biofuels in worst possible light;
- Alternative approaches likely to be more fruitful in genuinely evaluating effects of biofuels grown around the world. (MACQUARIE)

Comment: Farmers have been the target of indirect land use models in the past and Eureka fears that this may be another one of those situations. We must have a better understanding of the implications and foundation for indirect land use penalties against biofuels before moving forward. Indirect effects should be accurately assessed against all fuels, and ARB should have a better understanding of the implications of this flawed model. I hope that you as chair of ARB will direct staff to wait and do further study on the indirect land use change model and not include it in the LCFS. (EUREKA)

Response: See the response to Comment IV-9, above. The Board acknowledged in Resolution 09-31 that the available methods for estimating indirect impacts (including land use change) are relatively new. As they continue to undergo development, the uncertainty associated with the impact estimates from these methods will decrease. In adopting the LCFS, however, ARB has found that current uncertainty levels are not sufficient to call into question the existence of significant indirect land use change impacts. Our position on indirect land use change impacts can be summarized as follows:

- a. Although challenging to estimate, increased production of biofuels does lead to significant land use change.
- b. Land use change does release significant quantities of sequestered carbon into the atmosphere.
- c. Because the LCFS is explicitly intended to reduce carbon emissions from transportation fuels in California, ARB cannot ignore the reality of land use change emissions. We must account for them in the lifecycle fuel analyses we perform. To do otherwise would be to underestimate the carbon emissions from biofuels, and to thereby send the wrong signals to those in the fuel industry who will be developing the next generations of low-carbon fuels.
- d. Though many commenters (UCD2, for example) urge ARB to base its indirect land use change analysis on actual land conversion (and related) data, neither the necessary data, nor the methods to analyze that data appear to be available at this time. These comments make the case that the causes of actual land use change are often numerous, complex, and interrelated. In some cases, it is not even possible to identify all the reasons a given tract was converted. In most, it is impossible to accurately weight all the causes behind a given conversion event. Some of those who submitted this comment cited a study appearing in *BioScience Magazine* (see response to Comment IV-10) to support their arguments. The Board agrees that – for the reasons cited in these comments – estimating the indirect land use change impacts of fuel production from actual land conversion data is not currently possible. That is why it is necessary to estimate these impacts using a model that faithfully captures and quantifies the overriding economic forces that drive land use change. The Board’s approach is to use the most mature and highly regarded global economic model available – the GTAP – to estimate land use change impacts. The land conversion patterns the GTAP predicts are based on actual historical conversion patterns. Those historical patterns are described quantitatively, using empirical measurements of how conversion rates respond to commodity market price changes. The relationships in the causal link between commodity prices and land conversion are quantified using available empirical data. Based on the resulting elasticities and coefficients, the model is able to simulate the market behaviors that drive the land use change process with sufficient accuracy.
- e. The Board took immediate action in Resolution 09-31 to improve ARB’s ability to estimate land use change impacts – it directed the Executive Officer to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels. The workgroup is to present its findings to the Board in the form of recommendations and proposed regulatory amendments, if appropriate.

IV-30. Comment: It is now clear that there is a significant disparity in the values being obtained for indirect land use for the production of corn based ethanol depending on the assumptions utilized in the ILUC determination. The values range from 107 gCO₂e/MJ in the case of Searchinger, to a negligible value in the case of

Darlington where, consistent with many agricultural forecasts, exports are assumed constant to increasing. (ILCORN2)

Response: We agree that it is essential to work toward reducing the level of uncertainty surrounding current land use change estimates. ARB's approach to uncertainty reduction is described in the response to Comment IV-32. The Board also feels, however, that the value at the low end of the range cited in this comment – that of Darlington (Air Improvement Resources, Inc.) – is not valid, and can safely be discounted. Darlington's finding that ethanol production does not lead to land use change is predicated upon the faulty assumption that constant or increasing exports mean that export demand is met; obviating any need for American's trading partners to bring additional lands into agricultural production. The reason this assumption is faulty is described in the responses to Comments IV-10 and IV-43.

IV-31. Comment: We remain hopeful that the direction from ARB to establish an Expert Workgroup is, in part, to review and incorporate into the LCFS model the numerous data corrections that were provided to ARB during the initial public comment period ending April 22, 2009 and the subsequent public hearings ending April 23-24, 2009. With inaccuracies in the current proposed rule, it is imperative that the Expert Workgroup, in concert with harmonization with federal efforts, be allowed to complete its work to allow for the determination of science based ILUC values before the ILUC component of the carbon intensity value determination is implemented. (ILCORN2)

Response: As noted in the comment, the Board directed staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effect analysis of transportation fuels and return to the Board no later than January 1, 2011 with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. The Board directed that the workgroup should evaluate key factors that might impact the land use values for biofuels including agricultural yield improvements, co-product credits, land emission factors, food price elasticity, and other relevant factors. Staff will coordinate this effort with similar efforts by the U.S. EPA, European Union, and other agencies pursuing a low carbon fuel standard. Many land use change issues raised by this and other commentors will be addressed by the Expert Workgroup. ARB will seriously consider recommendations made by this group.

Furthermore, ARB will continue to review improvements in data and modeling presented by stakeholders and the scientific community and update the land use change modeling as appropriate. Mandatory program reviews in 2011 and 2014 as well as subsequent program reviews will facilitate these updates.

That said, we believe that with the modifications relating to ILUC made available for supplemental public comment, there is a sufficient basis at this time for adopting the ILUC component of the regulation.

IV-32. Comment: The uncertainty around ARB's ILUC determinations and the overall science of ILUC has been documented by numerous experts in the previous comment period prior to April 14, 2009, on the 1st ISOR, as well as in the research literature. Therefore, NCGA would like to reiterate recommendations that ARB delay its implementation of an indirect land use change component until such time as a scientifically accepted method to estimate indirect land use change is developed. (ILCORN2, NCGA2)

Response: After considering the staff's analysis and public comments, ARB has concluded that the state of the science is sufficiently advanced and reliable to adopt a regulation, and that the regulation uses the best information available. Acknowledging that land use change analysis does involve some degree of uncertainty, however, the Board directed the staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effects analysis of transportation fuels and return to the Board by January 1, 2011, with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. Also, see the response to Comments IV-9 and IV-10.

IV-33. Comment: On March 12, 2009, RFA President Bob Dinneen submitted to ARB Chair Mary Nichols and other California officials a 56-page study by Thomas Darlington of Air Improvement Resource, Inc. (AIR) entitled "Land Use Effects of U.S. Corn Based Ethanol." The paper concludes that expansion of corn ethanol production to 15 billion gallons per year in 2015 is unlikely to result in the indirect conversion of non-agricultural lands in the U.S. or abroad. This finding stands in stark contrast with ARB's modeling results. In the March 12 correspondence to Ms. Nichols, we requested "...a comprehensive and timely response from ARB to the AIR paper..." Unfortunately, we never received a response or even acknowledgement that the paper had been received and/or reviewed by ARB. This paper was briefly discussed at the April 23, 2009, hearing and ARB staff was asked by Board member Prof. Dan Sperling and Ms. Nichols to comment on the validity of its findings. In response, ARB staff did not question the soundness of the findings of the Darlington paper. (RFA3)

Response: ARB has received and reviewed the report prepared by RFA. Since the Informa Economics analysis that forms the basis for the RFA report was not submitted for review, an in-depth assessment of the analysis results could not be made. The key argument presented by RFA is that land use changes that occur outside the U.S. are not attributable to U.S. corn ethanol production since their modeling predicts that U.S. exports remain constant between 2001 and 2015. This result is predicated on large increases in crop yields (greater than those predicted by USDA) and a large decrease in cotton exports and land devoted to cotton production. They acknowledge that increased demand for cereal grains will occur due to increasing world population and increasing consumption of protein. They also estimate that total major crop area in the world will increase from 827.5 to 903.2 million hectares between 2001 and 2015. They assert however that none of the increase in crop area occurring outside the U.S. can be attributed to U.S. corn ethanol production if U.S. exports remain constant over

this time period. However, one could argue that if U.S. corn ethanol production remained steady over this time period, U.S. exports would increase as yields increase thereby resulting in less global land conversion required to meet increasing food demand. This argument raises the fundamental policy question: is the primary purpose of future increases in U.S. agricultural production to provide food for a growing world population or is the primary purpose to provide feedstock for fuel? ARB rejects the argument that the U.S. is not at least partly responsible for meeting the increase in world demand for food. We also wish to point out that constant or even increasing export levels do not mean that ethanol production is not causing land use change. The reasons for this are discussed in the response to Comments IV-10, and IV-43.

Also, see the response to Comment IV-1.

IV-34. Comment: While responding directly to the recently proposed modifications to the regulation, our attached comments also address a number of unresolved technical concerns that we have raised throughout the LCFS development process. In general, we continue to believe ARB's analysis of indirect land use change is wholly insufficient. We continue to believe the GTAP model employed by ARB for this analysis requires significant refinement and validation before it can be reasonably used as a regulatory tool to establish single-point enforcement parameters for the LCFS. (RFA3)

Response: See the responses to Comments IV-9 and IV-10.

IV-35. Comment: RFA believes that ARB *should not* adopt an ILUC carbon intensity value for ethanol as part of the Lookup Table at this time. This recommendation is based on the numerous unresolved technical concerns raised by stakeholders throughout the LCFS rulemaking process regarding development of the ILUC estimates. (RFA3)

Response: After considering the staff's analysis and public comments, the Board concluded that the state of the science is sufficiently advanced and reliable to adopt a regulation, and that the regulation uses the best information available. Acknowledging that land use change analysis does involve some degree of uncertainty, however, the Board directed the staff to convene an Expert Workgroup to assist the Board in refining and improving the land use and indirect effects analysis of transportation fuels and return to the Board by January 1, 2011, with regulatory amendments or recommendations, if appropriate, on approaches to address issues identified. Also, see the response to Comment IV-31.

IV-36. Comment: On April 17, 2009, RFA submitted detailed written comments responding to the ISOR. In particular, our comments focused on what we perceived to be the many shortcomings of ARB's analysis of ILUC effects using the GTAP model. RFA's comments explained that ARB's ILUC emission for corn ethanol could justifiably be reduced to 8 g/MJ, based on a number of adjustments that were documented in the comments in extensive detail. To date, RFA still

has not received a satisfactory response to the questions raised in those comments or feedback from ARB on why it has rejected the recommended modifications to its GTAP analysis. (RFA3)

Response: The FSOR section III. K and L contains responses to comments submitted by the commenter dated April 17, 2009. Also, see responses to Comments IV-6, 7, 18, 22, 23, 33, 34, 35, 37, 38, 50, 160, and 192.

IV-37. Comment: RFA and others have consistently raised concerns with ARB's treatment of exogenous improvements in crop yields in the ILUC analysis. In response, ARB's team developed a method of accounting for exogenous yield improvements. The method relies on a key assumption that yields improve at the same rate in the rest of the world as they do in the U.S. This method is far from perfect, but RFA is willing to accept the method until such time as a more detailed analysis is performed comparing yield growth in the U.S. to the rest of world. However, mistakes appear to have been made in the application of the method. The 13.25 billion gallon ethanol shock applied by ARB to the GTAP model is meant to estimate land use effects corresponding with ethanol volume increases from 2000/01 (the base year of the GTAP model) to 2015/16, when corn ethanol volumes were expected to be 15 bgy. Over this period, the USDA indicates yields will increase 23.4 percent, from 136.9 bu/acre in 2000/2001 to 69 bu/acre in 2015/16. In making its exogenous yield adjustment, ARB is adjusting only from 2001 to a 2006-2008 average yield (the increase in yield over this period is 9.5 percent; much lower than the 23.4 percent growth from 2001 to 2015 projected by USDA). This is inconsistent with the years of the ethanol shock. Thus, ARB's 30 g/MJ estimate logically only applies in 2007, not in 2015. If ARB were to use the 23.4 percent yield improvement projected by USDA over the same period of the ARB ethanol shock, the corn ethanol ILUC emissions would be 26.6 g/MJ rather than 30 g/MJ. This also suggests ARB's best estimate of average corn grain yields in 2015 is that they will be unchanged from 2006-08. ARB has not justified its reasoning for assuming crop yields will be static from 2006-08 to 2015, which is one-half the period of the associated GTAP ethanol shock. Again, failing to take into account the appropriate yield data substantially affects the rule's outcome, is arbitrary, and deprives the rule of evidentiary support. (RFA3)

Response: We agree that crop yields will likely increase in the future and that this will reduce the land use change impact of using crop-based feedstocks for biofuel production. However, our lifecycle assessments are designed to reflect current technology and agricultural practices and are not meant to predict future technologies or practices. Moreover, there is no compelling need to attempt to account for future changes to baseline values such as crop yields – our GTAP analysis is not time dependent. Although the size of the ethanol shock applied corresponds to the volumes expected in 2015, the model is not intended to simulate 2015 conditions. The shock could have been smaller without affecting the outcome – the sensitivity analysis showed that the model's outputs were not sensitive to the size of the ethanol production shock

applied. The lack of an explicit time dimension associated with the analysis, along with the insensitivity of the results obtained to the size of the shock applied; do away with any need to attempt to account for project future yields in the current model. As production technologies and agricultural practices evolve over time, the fuel lifecycle assessments will be periodically updated to reflect these changes. The two program reviews mandated by the LCFS in 2011 and 2014 as well as subsequent reviews will allow this.

IV-38. Comment: The Winrock emissions data released by U.S. EPA as a part of RFS2 shows much lower forest emissions in the U.S. than the Woods Hole data used by GTAP. ARB should consider the use of this more current data, as opposed to the Woods Hole data. (RFA3)

Response: The Winrock emissions factors are derived from the Woods Hole factors. The U.S. EPA retained Winrock International to modify the Woods Hole factors for us in its land use change modeling effort. There is no indication that the use of these derivative factors would strengthen our analysis. Lower emissions from the conversion of forest land is not, itself, a compelling reason to consider adopting the Winrock emissions factors.

IV-39. Comment: The U.S. EPA analysis for RFS2 shows significant reductions in livestock and rice methane for increased ethanol, which ARB's GTAP analysis ignores. (RFA3)

Response: The U.S. EPA's analysis accounted for several sources of both reduced and increased emissions that ARB's analysis did not consider. Another example is emissions from agricultural fertilizers (a source of N₂O emissions). The ARB will consider each of those sources as it works to improve its analytical approach.

IV-40. Comment: It is essential that verifiable data and updated research are taken into account with regards to ILUC assessment, so that it may accurately reflect current day agriculture practices. We are certain that an analysis based on available and reliable data will support an indirect impact on land use by sugarcane in Brazil much lower than the 46 gCO₂e/MJ value presently assumed by ARB. (AMYRIS)

Response: See the response to Comment IV-26.

IV-41. Comment: While Amyris supports that indirect effects should be considered or managed, mechanisms must be developed to promote best practices. Rewarding the efficient use of land for dedicated biofuels production (e.g. "energy cane") will accelerate the positive trends in land use efficiency across U.S. and global agriculture, thus minimizing direct and indirect effects. (AMYRIS)

Response: Although we agree that enlightened land management practices should be adopted around the world, ARB itself has neither the mandate nor the capacity to

actively promote such practices – especially on an international scale. Under the LCFS, we are authorized to establish the carbon intensity of existing fuels, and require fuel providers to reduce the carbon intensity of the fuels they sell in California by ten percent by 2020. By requiring this reduction, and by including land use change emissions in fuel carbon intensity values, as appropriate, ARB is helping to create the incentives necessary to improve land use practices. If and when such practices improve significantly, the Board will take that improvement into consideration as it revises the values in its fuel carbon intensity lookup table.

IV-42. Comment: We believe that there are many very well qualified individuals in both private and academia ranks that we will submit names for recommendation of inclusion on the expert work group. In addition, although we do not agree with indirect land use change, we believe that there should be a coordination of efforts amongst those that want to apply this penalty to biofuels. Those mainly should include here in the US, the Environmental Protection Agency, and if you look at the current figures, they do not match up. (NCB2)

Response: We appreciate the offer. To the extent possible, the Expert Workgroup will work toward standardized land use change evaluation methods. It is important to point out; however, that even a uniform analytical approach would not necessarily cause the Board's results to converge with the results obtained by U.S. EPA. The two study designs were somewhat different. Probably the most significant difference was that U.S. EPA analyzed the impacts of a 2.6 billion gallon ethanol increase in the year 2022, while the ARB modeled the effects of a 13.25 billion gallon increase imposed upon the 2001 world economy.

IV-43. Comment: In a presentation by a staff member titled "Draft Guidance to Regulated Parties On Establishing New Fuel Pathways and Sub-Pathways" it states on slide 20 that fuel with no indirect effects are those that do not displace food, feed or fiber crops. We again disagree with this analogy. Corn based ethanol is not displacing food, feed or fiber crops. The basis behind that statement is as you look back over time, producers across this nation have produced a corn crop that has continually met the demands of all uses. In fact, the supply of corn (less the usage for ethanol) has consistently been above 10 billion bushels; exports have stayed on trend line of around 1.9 billion bushels, in fact the U.S. had record exports in 2007-2008; all the while seeing a carryout that has increased the last 3 years. In addition, through corn-based ethanol, you have a feed co-production in the distiller's grains product that is displacing corn in the various livestock rations. All of this again is some of the basis of why we do not believe that corn based ethanol should be penalized for significant indirect effects such as land use change. (NCB2)

Response: The statistics cited in this comment in no way call into question the phenomenon of indirect land use change. Nor do they support the claim that "the corn crop has met the demands of all users." The fact that corn exports have stayed relatively constant, or even increased, does not demonstrate that exports satisfied

foreign demand for U.S. corn. If demand increased while exports stayed constant, demand was not met. If demand increased at a greater rate than the increase in exports, demand was not met. Prior to the recent economic crisis, increasing prosperity in many of countries that purchased American agricultural exports fueled a growing demand for those exports. That demand was in large part fueled by an increase in meat consumption, which required increased livestock feed imports. American corn and soybean exports provided some of those feeds. As corn is diverted to ethanol production domestically, less is available for export. That decreased availability will not be reflected in aggregate agricultural export figures. Exports could be rising – even to record levels – but still be lower than they would have been in the absence of the diversion of a portion of the corn crop to ethanol production. The GTAP model is designed to provide reliable estimates of this incremental but otherwise indiscernible decrease, and then to trace the effects of that decrease into the markets of our trading partners. These trading partners will seek to make up for the shortfall created when their demand for American imports is not fully met. One way to do this is to increase production locally. Another way to increase production, of course, is to convert non-agricultural land to agricultural uses. The important point here is that aggregate supply and export numbers do not tell us whether demand has been met – not even if supplies and exports are growing. Demand could easily be growing at a faster rate. The GTAP model brings supply data together with demand, and allows markets to adjust accordingly.

IV-44. Comment: The carbon intensity values proposed for the text of section 95486 are not supported by sound science. The authorizing legislation for the LCFS regulation requires the Board to rely upon the “best available economic and scientific information” in any regulation adopted to implement that legislation, and to assess “projected technological capabilities.” The carbon intensity values to be included in the new regulatory text for section 95486 establish what amount to penalties for the use of biofuels grown in the U.S. Those carbon intensity values would send the wrong signals to parties required to meet the average carbon intensity requirements in sections 95482 or 95483 of the proposed regulations. The carbon intensity values are based upon an application of models adapted from the work of the GTAP. The GTAP model structure is not suited for the purpose to which it has been applied here, which is to determine a specific gram per megajoule of energy value for what the LCFS regulation would treat as the “indirect” effects of a decision to use U.S. biofuels. In addition, the specific inputs and assumptions used in the GTAP model applied to develop the carbon intensity values (to the extent the inputs and assumptions can be ascertained) are unrealistic, and as one of the peer reviewers found, are not fully informed by the most recent “observed data.” (GE4)

Response: See the responses to Comments IV-9 and IV-29.

IV-45. Comment: The unintended impacts of the Lookup Table will also injure the interests of the California motoring public, and anyone who cares about reducing GHG emissions in an economically responsible manner. Among other

requirements, the Global Warming Solutions Act of 2006 (the “2006 Act”) directed the Board to consider the cost-effectiveness of its GHG regulations and impacts of those regulations on the economy. See Cal. Health & Safety Code § 38562(b)(5), (6). Because the Lookup Tables assign carbon intensity values to certain pathways that are inaccurate, and that are too high, the use of those specific pathways will be sub-optimal, and the State will not achieve the most cost-effective reductions in GHG emissions, as directed by the 2006 Act. (GE4)

Comment: The selection of scientifically defensible carbon intensity values that are based on the best available information is critical to achieving the goals of the 2006 Act. If the carbon intensity values send the wrong “signal” to the downstream regulated parties, then the LCFS regulation will result in the use of pathways that may increase GHG emissions above the levels that would result if the best possible carbon intensity values had been assigned to the various pathways in the regulation. (GE4)

Response: Growth Energy has submitted a number of comments describing in detail why it considers certain carbon intensity values to be inaccurate, and why the use of those pathways will, therefore, be suboptimal. In its detailed responses to those comments, we have either refuted Growth Energy’s arguments, or explained why any residual uncertainty about the carbon intensities in the lookup table is within acceptable bounds for this stage in the rulemaking process. The response to this comment, therefore, incorporates those responses by reference (primarily, Comments IV-5, 9, 10, 11, 12, 13, 14, 15, 16). In combination, these responses establish the basis for ARB’s finding that current lookup table is consistent with the provisions of the Global Warming Solutions Act of 2006.

IV-46. Comment: The “signals” communicated by the Lookup Table are also contrary to the goals and purposes of section 211(o) of the federal Clean Air Act and the 2007 Energy Act as a whole, as well as the California Legislature’s recognition of the State’s obligation to avoid interference with federal law. The 2005 Energy Act made it a goal of federal law, which has been preserved by the 2007 Energy Act, to provide “certainty for investment in production capacity of renewable fuels.” The Lookup Table, however, deprives the investments undertaken in reliance on the federal law of any value in the nation’s largest ethanol market. The Board has an obligation to consider the impacts of its regulations not only on California consumers and businesses, but also on the enterprises outside California that currently supply ethanol to California and whose continued role in the development of alternative fuels has been specifically confirmed by the U.S. Congress. As explained below, the compliance-path predictions contained in the ISOR and its Appendix E do not realistically depict the impact of the carbon intensity “signals” provided by the ARB Lookup Table, particularly in light of the proposed new cane ethanol pathways, and particularly for some of the Midwest corn ethanol pathways defined by the Lookup Tables. (GE4)

Response: See responses to Comments IV-8, and IV-45.

IV-47. Comment: We urge that ARB seek alternative policy mechanisms to address these concerns. Strategic elements of such policy should include the following:

- A defined process for dialog between ARB and the producer in which initial values for each feedstock be fully reviewed with the impacted bio-fuel producers
- A program structure allowing rapid inclusion and updating of ILUC values to represent latest science
- Identify mechanisms which reward best practices as reductions in agronomy inputs, reduced energy inputs and increased product yields are possible in the near future (AMYRIS)

Response: We agree that a streamlined and expedited process for updating existing pathways and adding additional pathways to the LCFS lookup table must be developed as quickly as possible. While staff is developing such a process, however, ARB has determined that, for reasons of public transparency and APA requirements, carbon intensity changes must be made as full regulatory changes as discussed in Section II.B. of this FSOR. The regulatory change process is relatively slow and cumbersome, but the Board is committed to transitioning to a rapid and efficient certification process as quickly as possible. Also, the Board in Resolution 09-31 directed staff to develop guidelines to assist applicants through the Method 2A and 2B process and to develop an informal process for estimating carbon intensity numbers for pathways under development.

IV-48. Comment: We are highly concerned that ARB accepted industry derived data for development of the two new sugarcane ethanol pathways, but would not accept industry-submitted data for establishment of direct carbon intensity values for other forms of ethanol earlier in the LCFS development process. While we do not question the legitimacy of the data supplied by UNICA, we are questioning ARB's criteria for acceptability and integration of data from stakeholders. There is no rational basis for rejecting the data supplied by RFA regarding energy use, co-product generation and other production factors for U.S. ethanol facilities but accepting the data supplied by UNICA regarding co-products and electricity generation for Brazilian ethanol plants. (RFA3)

Response: The statement that "ARB accepted industry-derived data for development of the two new sugarcane ethanol pathways, but wouldn't accept industry-submitted data for establishment of direct carbon intensity values for other forms of ethanol earlier in the LCFS development process" is not true. ARB has accepted industry-submitted data and revised the direct carbon intensity values for corn ethanol on several occasions. Examples include reducing the corn farming energy and reducing the emissions of nitrous oxide resulting from fertilizer application in response to RFA comments dated June 27, 2008. We have also rejected industry-supplied data for most

fuels including sugarcane ethanol. This FSOR gives our rationale for rejecting data submitted to ARB during the appropriate comment periods. See responses to Comments IV-160 and IV-184.

IV-49. Comment: We are curious as to if or when ARB plans to release its updated carbon intensity analyses of cellulosic ethanol pathways. For its examination of possible compliance scenarios, Table VI-3 of the ISOR presented preliminary carbon intensity values for cellulosic ethanol (from farmed poplar trees) and advanced renewable ethanol (from forest waste). ARB staff acknowledged that these carbon intensity estimates were preliminary in nature and that further research was needed. Does ARB plan to include cellulosic ethanol pathways in the lookup table that is included in the final regulation? Alternatively, will regulated parties who source cellulosic ethanol be required to establish new pathways under Method 2B? We encourage ARB to complete pathway analyses for several basic cellulosic ethanol pathways and include them in the lookup table so that regulated parties may use these fuels under Method 1, which is clearly the simplest means of certifying a fuel's carbon intensity. Failing to do so likely discourages the use of cellulosic ethanol (RFA3).

Response: ARB will develop several pathways for cellulosic ethanol. Likely candidates for pathways developed by ARB include cellulosic ethanol from farmed trees and agricultural waste. We will also accept applications to develop cellulosic ethanol pathways using the Method 2B process. The Board, in Resolution 09-31, directed staff to establish a prioritized list of pathways that the staff will develop and propose for incorporation into the Lookup Table. The list and proposed schedule is to be presented to the Board by December 2009. The work is expected to be done in 2010 to be available for the first compliance year of 2011.

ARB does not believe that the Method 2B process will discourage the use of cellulosic ethanol. Several alternative fuel producers have already initiated preliminary discussions with staff to develop new pathways using Method 2A and 2B. Moreover, in response to Board directives found in Resolution 09-31, staff is currently preparing a guidance document entitled, "Establishing New Fuel Pathways Under the Low Carbon Fuel Standard: Procedures and Guidelines for Regulated Parties," a draft of which is posted to http://www.arb.ca.gov/fuels/lcfs/fuels_pw_guidance.pdf. This non-binding document will help to streamline the Method 2A or 2B process for approving a carbon intensity value for incorporation into the Lookup Table.

IV-50. Comment: Regarding the suggested modifications to section 95486, we are concerned by the fact that ARB is proposing that all new or modified pathway applications go through the full formal rulemaking process. The rule should provide the ability for new or modified pathways to be approved upon application by a member of the public. Rulemaking should not be required and will have several negative consequences, as described below.

1. The length and complexity of the full rulemaking process is likely to unnecessarily delay the deployment of new technologies to the market. Subjecting each and every new or modified pathway application to the requisite public comment periods, public hearings, and review by OAL appears overly burdensome and unnecessary.
2. A rulemaking process creates the risk of disclosure of trade secrets and proprietary information about unique processes/technologies. So far, ARB staff has not provided a satisfactory explanation of how it will manage trade secrets and proprietary information/data that are submitted as part of the Method 2 process. Without an assurance from ARB that this information will be handled properly, low carbon fuel producers are very unlikely to disclose the information required by ARB to establish a new or modified pathway.
3. Because no two low carbon fuels production processes are exactly the same, ARB should expect to receive a large amount of applications for new or modified pathways (provided that the issues surrounding confidentiality of trade secrets/proprietary data are resolved). Subjecting each application to the full rulemaking process will undoubtedly place a significant additional administrative burden on the agency.

Due to these concerns, we strongly urge ARB to revisit the process for considering applications for new or modified pathways. The current proposal would undoubtedly discourage low carbon fuel providers from applying for certification of a new or modified pathway, which runs counter to the stated goal of the LCFS to stimulate innovation and new low-carbon fuel technologies in California (RFA3).

Response: With respect to the comment in 1., we disagree. As discussed in Attachment B to Resolution 09-31 and in Section II.B. of this FSOR, staff became concerned that under the original proposal, the Executive Officer's action of certifying carbon intensity values could have the effect of establishing an important element of the regulation without following the rule-adoption process or applying robust criteria in the regulation that significantly narrow the Executive Officer's discretion in certifying carbon intensity values. This could have resulted in disapproval of the mechanism by OAL. Concerns were also raised that, as initially proposed, the certification process might not be sufficiently transparent.

Accordingly, the Board agreed with staff's recommendation that section 95486 be modified to make the Lookup Table and its carbon intensity values part of the regulation. While the carbon intensity values could only be amended or expanded by regulatory amendments, in Resolution 09-31 the Board delegated to the Executive Officer the responsibility to conduct the necessary rulemaking hearings and take final action on any amendments, other than amending indirect land-use change values included in the Lookup Table as adopted in this LCFS rulemaking. This is appropriate because of the technical nature of the carbon intensity determination and the need to expedite the amendment process. Staff intends to develop for consideration by the

Board specific guidance on establishing carbon intensity values that, if feasible, could become part of a certification process. There is currently a draft of these guidelines on the LCFS website. The Board, in Resolution 09-31, directed staff to develop the certification process and bring it to the Board for approval. In the interim, the Board directed staff to prepare guidelines by December 2009 to assist applicants in establishing new or modified pathways.

B. Coproducts and Coproduct Credits

Co-Products

IV-51. Comment: In its application of GTAP, the ARB staff assumed that one pound of distiller's grain replaces or displaces one pound of corn in livestock and poultry feeding practices. Based on a 1:1 ratio, the ARB staff estimated a credit of 33 percent for corn-based ethanol. The best available research, however, demonstrates that ARB's 1:1 ratio is not correct. A recent study conducted by the Argonne National Laboratory concluded that "1 lb. of distiller's grains displace 1.28 lb. of conventional [base] feed ingredients," which contains both corn and soy meal for beef, dairy cattle, and swine. In replacing base feed, distillers' grains are used to replace some soy meal as well as corn. It is well documented that soy yields per acre are far lower than corn yields per acre. Therefore, any soy meal that DG's replace has a greater land use credit than base feed and corn meal it replaces. The Argonne study found that 24 percent of the 1.28 lbs. of base diet replaced by 1 lb. of DG's was soybean meal. With this updated Argonne data, the land use credit would be nearly 71 percent. Another study, conducted by Dr. Gerald Shurson from the University of Minnesota included poultry feeding. If one incorporates Dr. Shurson's numbers, the land use credit becomes 74 percent. At a land use credit of about 33 percent, according to ARB, on a net basis 21 million acres are used to make 15 BGY of corn ethanol, which is 25 percent of corn land. However, if the land use credit is at least 70 percent, then 11 million net acres would be used for ethanol, amounting to about four percent of U.S. farmland. (GE4)

Response: The analysis presented by staff is a balanced approach to DGS co-product credit and represents analysis based on currently available data. To assess the future net impact of DGS resulting from 15B gallon ethanol production, as a feed replacement, market and research studies will have to be conducted to account for various factors discussed in the ISOR such as the effects of variability in quality, transportation challenges, animal response to this supplement, price competitiveness, types of feed supplements displaced, etc. Data from these studies will be considered. In approving the LCFS, the Board considered the evaluation of this issue and recognized that new data from studies in the future may allow for refinements of the current analysis. New information also may be considered by the Expert Workgroup (directed to be established per Resolution 9-31) to be formed by staff with a report due to the Board by December 2010, and additionally during two mandatory program reviews to be done in 2011 and 2014. Also, see response to Comment M-1.

IV-52. Comment: ARB is making incorrect statements about the nutrient composition of DDGS, about the utilization and digestibility of protein and amino acids in DDGS, about the value of phosphorus in DDGS, about the consequences of the Maillard reaction, and about the nutritional effects of the particle size in DDGS. As has been pointed out by these feeding and nutrition experts, there is strong scientific evidence to support the use of DDGS in diets fed to beef cattle, dairy

cows, swine, and poultry and there is a plethora of information available about the use of DDGS in diets fed to livestock and poultry. The nutrition experts also point out that it is incorrect when ARB postulates that “it is evident that significant barriers to the widespread adoption of DDGS as livestock feed exist” – in contrast all the nutritionists point out that livestock and poultry producers have been very receptive to the use of DDGS because it contributes to a reduction of diet costs. (ILCORN2).

Response: These comments have been addressed in the responses to Comments M-1 and M-2. The analysis presented in the ISOR served to highlight the challenges that need to be considered for the effective utilization of DGS from the production of 15B gallons of corn ethanol. The analysis did, however, consider all of the DGS to be utilized as an animal replacement feed.

IV-53. Comment: The ARB staff has also suggested that DDGS is a poor feedstock for swine. But as Dr. Hans Stein from the University of Illinois, has stated in his comments, “The reality is that swine producers, like other livestock and poultry producers, have been amazingly quick to adopt and embrace feeding diets containing DDGS. The total usage of DDGS in diets fed to swine in the U.S. has increased from around 100,000 Metric tons in 2001 to more than 3 million Metric tons in 2008. From this usage it is evident that swine producers have been exceptionally successful in taking advantage of the opportunity of feeding DDGS to swine.” These comments and the research they report require significant change in the treatment of DDGS in the LCFS analysis. (GE4)

Response: The analysis in the ISOR did account for the DGS resulting from 15B gallons of ethanol production to being used by the livestock industry. With DGS becoming widely available from the increased corn ethanol production, it has found expanded usage among various livestock industries. The analysis presented did in fact consider swine feed industry as being one among many livestock industries that would utilize DGS as a replacement feed. Also, see response to Comment M-1.

IV-54. Comment: The ARB staff has speculated that transportation of distillers’ grains significantly limits their use. The ARB staff’s concerns about transportation centered on moisture content, lot size and particle caking. As Dr. Justin Sexten has noted in his comments, however, ethanol plants:

- Have the ability to modify drying processes to produce wet, modified or dry products to suit market needs relative to livestock feed area proximity;
- Have various additives and storage methods available to increase storage time beyond three to seven days;
- Have feed mills and brokers that can sell smaller lot sizes to farms unable to receive full loads;
- and new research shows significant improvements in DDGS flow agents and pelleting technologies. (GE4).

Response: These comments have been addressed in the responses to Comments M-1 and M-2. The analysis presented in the ISOR served to highlight the challenges that need to be considered for the effective utilization of DGS from the production of 15B gallons of corn ethanol. The analysis did, however, consider all of the DGS to be utilized as an animal replacement feed.

C. Lifecycle Analysis

Corn Ethanol Pathway

IV-55. Comment: The carbon intensity values in the ARB Lookup Table place Midwest corn ethanol biorefineries at a distinct and unjustifiable disadvantage. The most advanced Midwest dry mill refineries use energy sources at least as low in GHG emissions as any ethanol production facility operated in California in the recent past. Based on the current record ARB has no sound basis for concluding that all or most Midwest corn biorefineries will use any type of process power not as “clean” as California biorefineries, or for concluding that GHG emissions from the Midwest facilities will be higher than from the California facilities. ARB’s decision to treat all non-California biorefineries differently from all California refineries has no scientific basis, when the performance of modern Midwest facilities is considered. The Board needs to address this issue and explain clearly, why it has made this distinction. It is also noteworthy, and necessary for ARB to respond to the fact that, the estimates of direct GHG emissions estimated by U.S. EPA for corn ethanol pathways are in general much lower those reflected in the Lookup Table. ARB has articulated no sound basis to dispute the estimates of direct GHG emissions in EPA’s current publications. (GE4)

Response: There are less than 10 California corn to ethanol biorefineries, all modern and using advanced technology. In addition, California electricity has an inherently lower carbon intensity compared to Midwestern electricity, which is largely produced from coal-fired facilities. Midwestern facilities, which can document that, they qualify for the same carbon intensity as California facilities will be allowed to use the same carbon intensity for the type of facilities and products described. There are a number of sub pathways for Midwestern plants. As noted, a facility can use the carbon intensity that information supports. In cases where a producer can demonstrate lower carbon intensity for its ethanol, Method 2A can be used. As for U.S. EPA’s analysis, this was projected for 2022 and beyond where several technological advances are considered. For the LCFS program, there will be two mandated program reviews in 2011 and 2014 at which time these issues can be considered.

IV-56. Comment: Modest corrections to the GREET model to reflect the state of the dry grind ethanol industry today have a significant impact and reinforce the importance of using current quality data. Updating the current dry grind industry production figures (e.g. ethanol and DDGS outputs and energy inputs), in the CA-GREET model), results in an 8.8 gCO₂e/MJ carbon intensity reduction; a 13.3 percent reduction in direct emissions. (ILCORN2)

Response: The analysis presented in the ISOR uses an industry average data for corn ethanol production. There may be pathways or modifications to the pathways in the ISOR (more efficient processes or other parameters) which may translate to lower carbon intensities compared to those published in the ISOR. To allow for this, a mechanism to use Methods 2A and 2B has been incorporated into the regulation. This

will allow producers to develop their pathway-specific carbon intensity values provided they can be supported with verifiable data and a rulemaking is completed. See also response to Comment K-1.

IV-57. Comment: The University of Illinois at Chicago, under the direction of Dr. Steffen Mueller, is currently conducting a rigorous survey of the ethanol industry to provide current production values to Argonne National Laboratories to allow for an update of the GREET model. This study has an anticipated completion of year end. ARB should immediately update its ethanol production numbers when presented with this new information. (ILCORN2).

Response: The Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014, which will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate. The information likely to be supplied could be considered when these reviews are made. Also, Method 2A and 2B can be used to take advantage of new studies.

IV-58. Comment: ARB has also not provided pathways for technologies that are available to the corn based ethanol industry today, but are not broadly adopted, that significantly reduce the carbon intensity of corn based ethanol. A process by which annual updates of the current pathway carbon intensity values can occur is critical to encourage the further reduction in carbon intensity values of renewable fuels. Proactive definition of potential new pathways is also critical or adoption of these new technologies is unlikely in the future. Additionally, proactive identification of and approval of new pathways will dramatically simplify the resource burden on ARB. We are prepared to work collaboratively to bring forward these pathways to ARB. (ILCORN2)

Response: Staff looks forward to working with the commenter. In Resolution 09-31, the Board directed staff to develop a prioritized list of pathways to be developed. Such information will be valuable in establishing such a list. As appropriate, for these new pathways, Method 2A or 2B can be used to establish the carbon intensity.

IV-59. Comment: ARB staff recommended several changes to the carbon intensity Lookup Table based on recently completed additional fuel pathway analyses. We are still reviewing the new pathway GREET documentation used to establish the direct carbon intensity values for the newly established pathways. Overall, we are highly concerned that ARB accepted industry-derived data for development of the two new sugarcane ethanol pathways, but would not accept industry-submitted data for establishment of direct carbon intensity values for other forms of ethanol earlier in the LCFS development process. While we do not question the legitimacy of the data supplied by UNICA, we are questioning ARB's criteria for acceptability and integration of data from stakeholders. There is no rational basis for rejecting the data supplied by RFA10 regarding energy use, co-product generation and other production factors for U.S. ethanol facilities

but accepting the data supplied by UNICA regarding co-products and electricity generation for Brazilian ethanol plants. (RFA3)

Response: Please see response to Comment IV-48.

IV-60. Comment: Since the last available data on the efficiency of the ethanol industry was obtained by the 2002 USDA Survey, it is clear that ethanol plant production values utilized within GREET and the California LCFS model do not reflect current day efficiencies. The IEA report notes that between 1983 and 2005, the energy requirements for producing ethanol in a dry mill plant decreased by 63 percent. (ILCORN2)

Response: The values generated using CA-GREET take into account the efficiencies of farming practices, crop collection and transportation, fuel production, co-product generation, and distribution of fuel and the carbon intensity values generated using CA-GREET represent weighted average values. There may be pathways or modifications to ISOR published pathways (more efficient processes or other parameters) which may translate to lower carbon intensities compared to those published in the ISOR. To allow for such producers a mechanism to use, Methods 2A and 2B have been incorporated into the regulation. These will allow producers to develop their pathway-specific carbon intensity values provided they can be supported with verifiable data and a rulemaking is completed. Additionally, the Board has directed staff to conduct mandatory regulatory reviews in 2011 and 2014, which will provide opportunities to monitor developments related to all stages of fuel production and make carbon intensity adjustments when they are appropriate.

Sugarcane Pathway

IV-61. Comment: BP believes that the two additional pathways more accurately reflect the variety of low carbon operations used to produce Brazilian sugarcane ethanol. As we are investing in state of the art facilities in Brazil, we appreciate that these additional pathways create a mechanism to encourage efficient, low carbon practices. For this reason we encourage ARB to pursue the following additional improvements to sugarcane pathways:

- a. Update the existing assumptions for all sugarcane pathways to ensure that assumptions and practices in California GREET reflect current practices.
- b. Anticipate the improvements that new investment will catalyze for the entire industry and schedule periodic updates to incorporate these improvements when they are achieved. Furthermore, we would stress improvements and updates specifically to Scenario 2 pathway entitled "Brazilian sugarcane with average production process and electricity co-product credit." This pathway in particular will be the category where most new investment will qualify. Updating this pathway to reflect the best practices of the industry will encourage investment towards lower carbon innovation.

Ultimately these changes will allow sugarcane ethanol to be accurately represented as a low carbon option that is critical to the success of the LCFS program. (BP3)

Response: The September 23, 2009 version of the sugarcane ethanol pathway, incorporated by reference in section 95486(b)(1) as made available with the Second 15-Day Notice, was one of four pathway documents reflecting minor changes to correct slight calculation errors, rounding errors, and errors that occurred when outputs from the CA-GREET model were transferred into the supporting pathway document. To allow for producers with additional improvements in carbon intensity or for new pathways, the regulation has incorporated Methods 2A and 2B. These allow for new pathway carbon intensities when supported with verifiable data, after a rulemaking is completed

IV-62. Comment: Once again, we request that ARB should review the GREET model and supporting research and adjust the values for straw yield in CA-GREET for sugarcane ethanol. Moreover, we urge ARB to revise its original sugarcane pathways in order to correct this error given significant implications to the underlying calculations. (UNICA2)

Response: The analysis reflected in the sugarcane ethanol pathway incorporated by reference in section 95486(b)(1) as adopted is appropriately based on available data and calculated for average farming conditions in Brazil. (See response to Comment IV-125.)

IV-63. Comment: UNICA urges ARB to update its values for harvested cane transportation to the mill to reflect reality in Brazil, which clearly indicates that average trucks are 42, not 17, tons. (UNICA2)

Response: The analysis used a GREET value for truck transport. Another commenter (see Comment IV-67) indicates that this value should be 34 tons. Therefore, there are different values for reported truck capacities and staff's position at this time is that when additional data becomes available to support that all the cane is being transported using such trucks, appropriate refinements could be performed using Method 2A.

IV-64. Comment: We request that ARB adjust down the lime (CaCO_3) values in its GREET analysis for Brazilian sugarcane. (UNICA2)

Response: Lime is a major feedstock for several operations in Brazil including cement, steel, and farming. Staff was not able to independently verify total production in Brazil and total imports into Brazil. When such information becomes available, staff will consider refinements to current estimates for lime production. (See response to Comment IV-63)

IV-65. Comment: UNICA believes that it is highly speculative and arbitrary to assume that the energy consumption and associated emissions of the ocean tanker's round trip be attributed to sugarcane ethanol. (UNICA2)

Response: There are no specific data to support the claim that the commenter makes regarding the return trip of the ocean tanker to Brazil after unloading the ethanol. There may be instances where this may happen but verification of such claims across all the shipments is difficult.

IV-66. Comment: Amyris analyzed two additional scenarios for sugarcane ethanol to account for improved harvesting practices and the export of electricity from sugarcane ethanol plants in Brazil using energy from bagasse. The first additional scenario recognizes mechanized harvesting of cane which is replacing the traditional practice of burning straw before harvesting cane. The second scenario includes export of electricity beyond that required for processing in the plant (co-product credit). The new analysis allows Brazilian ethanol to receive a credit of more than 15 gCO₂e/MJ, due to the use of bioelectricity from sugarcane cogeneration (7 gCO₂e/MJ) and the mechanization of sugarcane harvest (8.2 gCO₂e/MJ). (AMYRIS)

Response: This has been done. Two additional pathway documents for sugarcane ethanol were published in July 2009 to account for situations where mechanical harvesting of cane and using of bagasse for electricity production exist.

IV-67. Comment: The average truck load capacity for sugarcane transportation is 34 tonnes or more, not the ARB value of 17 tonnes. In this case the CO₂e per MJ for cane transportation should be reduced by half (ARB Document Table 2.04). (EMBRAPA)

Response: The analysis used a GREET value for truck transport (see response to Comment IV-63).

IV-68. Comment: In the limited time available to prepare these comments, an expert in regulatory analysis, Mr. James Lyons, has examined the empirical basis for the new cane ethanol pathways. Mr. Lyons' analysis has revealed the following apparent deficiencies:

- The values of the electricity co-product credit is, as acknowledged by the authors cited as its source, based on the assumption that the displaced electricity will come from natural gas power plants "which are believed to be the marginal electric power plants in Brazil." But the value of the co-product credit could be much lower if the displaced electricity is based on the average Brazilian generation mix which is 83 percent hydro-power (see Lyons Dec. ¶ 10 and pp.19-27);
- The analysis of the mechanized harvest pathway fails to account for the GHG from the fuel used to perform the harvest underestimating GHG

- emissions, and thus producing an incorrect carbon intensity value (*id.* ¶¶); and
- The analysis of the combined electricity and mechanized harvest co-product pathway fails to account for differences in ethanol production from green mechanically collected cane, as opposed to burned manual collected cane, which will affect the carbon intensity value and which is likely to affect also the co-product credit for electricity generation. (*Id.*).

Based on Mr. Lyons' analysis, it is far from clear that the new cane ethanol pathways would meet the criteria for application of Method 2A in proposed section 95486. (See Lyons Decl. ¶ 10 and pp. 19-27.) The upshot is that the Executive Officer is now proposing to include in the Lookup Table a set of carbon intensity values favoring overseas ethanol manufacturers, which those manufacturers could not have obtained if they were required to use the same procedures as any other group of manufacturers seeking to adjust the carbon intensity values in the Lookup Table, *i.e.*, the procedures required by Method 2A. Such an approach to regulating low-carbon fuel pathways is arbitrary and not consistent with the legislative purpose of the LCFS regulation. (GE4)

Response: The analysis for co-product exported electricity considered marginal electricity derived from natural gas since this is the most likely "incremental" source of electricity that will be generated to keep up with new demand.

When all factors are considered, ARB does not anticipate significantly increased GHG emissions arising from the use of harvesting equipment. Nor do we expect significant differences in the energy requirements for the processing of sugarcane from mechanical harvesting versus sugarcane harvested manually after burning. ARB will form an Expert Working group, which will consider these issues and recommend modifications if necessary.

Suppliers that use the mechanically harvested, exported co-gen power pathway, have to provide verifiable evidence for such practices for their ethanol to use the carbon intensity for that pathway.

IV-69. Comment: ARB's new proposed pathway for sugarcane ethanol includes a cogeneration credit of 7 gCO₂/MJ that is accurate for 2008 but will require updates in coming years. Therefore, we recommend that that ARB plan for an update to the cogeneration credits to reflect the expected increase of cogeneration electricity surplus exported to the grid. (UNICA2).

Response: There are two mandated reviews in 2011 and 2014 at which time this will be visited and appropriate refinements considered. See also Comments IV-63 and IV-64.

IV-70. Comment: The Input Values for Ethanol from Brazilian Sugarcane (Appendix B). The input value for Sugarcane Harvest Yield of 75 tonnes per hectare (CA-

GREET Default) is not correct. The current national harvest yield for ethanol sugarcane production in Brazil is 82.7 tonnes per hectare, as shown in Table 1.00 (CONAB, 2009 www.conab.gov.br). Since the correct harvest yield of sugarcane in Brazil is 82.7 tonnes per ha, all the Tables of the Document "Detailed California-Modified Greet Pathways for Brazilian Sugarcane Ethanol: Average Brazilian Ethanol, with Mechanized Harvesting and Electricity Co-product Credit, with Electricity Co-product Credit (July 20, 2009)" should be reviewed and corrected. (EMBRAPA)

Response: The analysis in the ISOR considered average yields for Brazilian-produced sugarcane. There may be regions where yields could be higher, but ARB chose to use an average approach. This was done because production can vary for a number of reasons that are both in the control and outside the control of the grower. For instance, crop price can influence how much fertilizer is used and weather is always a major variable. If the average production increase, Method 2A can be used to refine numbers as new data becomes available.

LNG Pathway

IV-71. Comment: In their analysis of the "North American NG, Liquefied in CA and used in CA" pathway – ARB should have modeled a generic large LNG production facility rather than the small facility it did model. It is unfortunate that ARB staff has in the time since the April Board meeting not modeled the largest state-of-the-art LNG production facility in California. As a result, none of the LNG pathways recently published properly reflect the low carbon viability of California based LNG production from North American natural gas. Clean Energy respectfully requests that ARB modify the LNG pathways published on July 20th to reflect the same low carbon production technology for California based LNG plants as used in their calculations of Overseas Liquefaction (e.g. 7.40 gCO₂eq/MJ for both overseas production and California production). This will give a much more realistic picture of the low carbon potential of LNG than the current published pathways. (CE5)

Response: Staff has updated the new LNG pathway document; the September 23, 2009 version incorporated by reference in section 95486(b)(1) as adopted reflects higher efficiency liquefiers that could operate in California.

IV-72. Comment: The main variable in all the LNG pathway analyses is the carbon intensity of the liquefaction process, and the main variable in the analysis of liquefaction processes is the efficiency of the process. Several members of the CNGVC – Clean Energy, Waste Management and Sempra Utilities – have detailed information on the liquefaction processes used in the production of their LNG, and we urge Board staff to work closely with them to determine the most accurate calculation of the carbon intensity for the LNG they are providing. (CNGVC3)

Response: Staff has worked with industry and reviewed available information to develop two separate liquefaction efficiencies for NG liquefaction in California. (See also responses to Comments IV-71).

IV-73. Comment: The pathway document utilizes values for energy intensity (405 Btu/ton-mile) and pipeline leak rate (0.08 percent) that are substantially understated and not supported by publically available information. Both of these values require revision to rectify errors made in their derivation (NA NG to CNG Pathway, Page 30). (SEMPRA3, SEMPRA4).

Response: The energy intensity value was from the Argonne GREET model. The model calculated this value based on DOE and EIA published values for NG transmission in the U.S. The pipeline leak rate was calculated from data provided by SoCal Edison during the AB 1007 study. Additionally, staff worked with another group at ARB working on NG recovery and transmission data. Based on preliminary data provided to staff on leak rates from pipelines (made from steel), the 0.08 rate is adequate and does not understate fugitive emissions from transmission of NG as detailed in the pathway document.

IV-74. Comment: The pathway includes a recovery efficiency of 97.2 percent for NA natural gas based on the GREET default value (Page 40). This value should be revised to reflect more current information. (SEMPRA3, SEMPRA4)

Comment: The pathway document includes a processing efficiency of 97.2 percent for NA natural gas based on the GREET default value (Page 40). This value should be revised to reflect more current information from EIA for 2006 regarding the average fuel gas consumption rate for the U.S. associated with natural gas production. (SEMPRA3, SEMPRA4)

Response: This value is a GREET default which has been incorporated into the CA-GREET model. Note that fugitive emissions from NG recovery are accounted separately and not included in the recovery efficiency calculation. When the impacts of recovery efficiency and fugitives are combined, the total for NG recovery compares reasonably well with published information and also that provided by SEMPRA (see Comment IV-75). Also see response to Comment IV-73.

IV-75. Comment: The pathway document includes an emissions rate of 1,237 gram CO₂/MMBtu for vented CO₂ associated with NA natural gas based on the GREET default value (NA NG to CNG, Page 27). This value should be revised to reflect more current information. (SEMPRA3, SEMPRA4)

Response: This value is a GREET default which has been incorporated into the CA-GREET model. Also see responses to Comments IV-73 and IV-74.

IV-76. Comment: The pathway document includes a distance of 50 miles for the LNG truck transport from the liquefaction plant in California to the LNG station.

Existing plants that liquefy pipeline gas are located near the California border or outside Los Angeles. A value of 100 to 150 miles would be more appropriate for the typical distance for trucked LNG. (SEMPRA3, SEMPRA4)

Response: The NG pathway utilizes transporting NG to within California followed by liquefaction within CA. Based on this scenario, 50 miles was used as an average transport distance from LNG production to refueling station. The pathway documents incorporating higher efficiency liquefiers consider that such liquefiers will be available in California and deliver LNG within an average 50 mile radius.

IV-77. Comment: The energy use and all associated emissions (other than vented CO₂) should be revised to zero for the natural gas processing associated with imported LNG. (Pages 21 & 35) (SEMPRA3, SEMPRA4).

Response: The analysis utilized North American recovery data to calculate emissions from NG recovery for overseas locations. This is primarily due to lack of industry wide data for NG production from regions that could be delivered to California as LNG. Some of the information provided by SEMPRA was based on projected emissions and other variables for plants likely to become operational in the future. Method 2A is available for establishing sub-pathways with lower carbon intensities.

IV-78. Comment: Table 3.01 includes a distance of 8,769 miles between the LNG source in Southeast Asia and the LNG terminal in Baja Mexico. Southeast Asia is more representative of an LNG market than a supply region and is a further distance from Baja Mexico than likely LNG supply sources. The two primary sources of LNG for the Baja Mexico LNG terminal are Tangguh, Indonesia and Sakhalin, Russia. The average shipping distance to Baja Mexico for these two supply sources is 5,773 nautical miles. This is a more appropriate value to utilize in the pathway calculation. (SEMPRA3, SEMPRA4)

Response: The transport distance used was an average value to account for shipment of LNG from South East Asia, a likely source for LNG to California. As for shipments from other locations, this situation could be considered if verifiable supply contracts are provided to ARB. The impacts of variability in shipping distances are typically small. If the differences meet the minimum requirements for Methods 2A or 2B, the providers can apply for a new carbon intensity value.

IV-79. Comment: The pathway document includes a distance of 250 miles the LNG truck transport from Baja, Mexico to California (Page 41). The actual distance from the Baja, Mexico LNG terminal to primary California markets is much shorter with 150 miles being a more appropriate average value for calculating emissions. (SEMPRA3, SEMPRA4)

Response: Using Google Earth, the truck route from Baja to various locations in Southern California can be estimated to be about 250 miles.

IV-80. Comment: The pathway document includes a distance of 250 miles for transporting natural gas by pipeline from Baja, Mexico to California (Page 28). The actual distance from the Baja, Mexico LNG terminal to primary California markets is much shorter with 150 miles being a more appropriate average value for calculating emissions. (SEMPRA3, SEMPRA4)

Response: See response to Comment IV-79.

IV-81. Comment: The pathway document utilizes values for natural gas recovery efficiency (97.2 percent and natural gas leak rate (0.35 percent) based on the CA-GREET default values (Page 40)). The derivation of these default values is not adequately supported and should be replaced by values developed based on publicly available information. Past studies and recent project environmental reports provide sufficient information to support more appropriate values. Based on this information we would recommend values of 99 percent for the natural gas recovery efficiency and 0 percent for the natural gas leak rate. (SEMPRA3, SEMPRA4)

Response: See response to Comments IV-73 and IV-74.

IV-82. Comment: Given that Linde and Waste Management will soon be the largest producers of LNG from landfill gas in California, we recommend that ARB should publish an LFG-to-LNG pathway that accounts for the latest technologies we are now using. We understand the value of having a generic pathway for LFG-to-LNG, but we respectfully recommend that ARB immediately publish a new "sub-pathway" for LFG-to-LNG that accounts for facilities using mixed refrigerant liquefaction systems and onsite biogas energy production. We firmly believe this sub-pathway should be included in the current rulemaking process and we (Waste Management and Linde) stand ready to assist ARB in any way we can to make this happen. (LINDE)

Response: This has been done. The September 2009 release of documents for new pathways include the higher efficiency liquefaction process to convert LFG derived NG gas to LNG. As for onsite biogas derived energy production, this is likely to be a site specific issue and could be addressed under Method 2A when supported by verifiable data.

IV-83. Comment: ARB should publish an LFG-to-LNG pathway that accounts for the latest technologies we are now using. We understand the value of having a generic pathway for LFG-to-LNG, but we respectfully recommend that ARB immediately publish a new "sub-pathway" for LFG-to-LNG that accounts for facilities using mixed refrigerant liquefaction systems and onsite biogas energy production. We firmly believe this sub-pathway should be included in the current rulemaking process and we (Waste Management and Linde) stand ready to assist ARB in any way we can to make this happen. (WM4)

Response: See response to preceding comment.

Biodiesel/Renewable Diesel Pathways

IV-84. Comment: Darling encourages ARB to consider a broader survey of rendering industry data for natural gas and electricity used to produce Tallow and UCO too. This may help to address concerns that the UCO pathway and the Tallow pathway relied on very different sources to obtain data on the energy used for processing UCO and rendering animal by-products. More consistency in the approach used in each of these pathways is appropriate because the same renderers frequently use the same site for both processes: processing UCO and rendering of animal by-products. (DARLING)

Response: Staff has updated the pathway documents for Used Cooking Oil to Biodiesel and Tallow to Renewable Diesel. September 23, 2009 versions, incorporated by reference in section 95486(b)(1) as adopted, provide additional pathways that utilize lower energy for rendering operations. Producers need to provide verifiable data to utilize the carbon intensities calculated in the Lookup Tables. As for facilities that process both feedstocks, producers may request staff to consider the development of average intensities based on feedstock processed annually (or other time period).

IV-85. Comment: Develop a pathway for making biodiesel from Tallow produced in California as soon as is practicable. (DARLING)

Response: This pathway can be developed through the use of Method 2A. In Resolution 09-31, the Board directed the Executive Officer to work with biofuel producers and other interested stakeholders to identify specialized fuel pathways such as anaerobic digestion, thermochemical conversion of biomass feedstocks and additional liquefied natural gas pathways that the Board staff will develop and propose for incorporation into the Carbon Intensity Lookup Table. The prioritized list, with a proposed development schedule, shall be presented to the Board by December 2009.

IV-86. Comment: Remove the transportation of Tallow from the Midwest to make renewable diesel and modify the Tallow to renewable diesel pathway to apply to Tallow produced in California. (DARLING)

Response: Methods 2A and 2B allow this to occur. Method 2A would allow appropriate feedstock transport distances to be developed for tallow produced in California and new sub-pathways to be established. See also the response to comment IV-85.

IV-87. Comment: Develop a pathway using UCO as a feedstock for renewable diesel in a dedicated facility similar to the one recommended for Tallow. (DARLING)

Response: See response to Comment IV-85.

IV-88. Comment: Consider methodology that can be applied to determining the carbon intensity of blended feedstocks consisting of various proportions of UCO and Tallow when such blends are used as feedstock for either biodiesel or renewable diesel. (DARLING)

Response: As for facilities that process both feedstocks, producers may approach staff to consider the development of average intensities based on weighted feedstock processed annually (or other time period). This is allowed under Method 2A subject to 5 g/MJ and volume.

IV-89. Comment: In the fourth paragraph on page 15, ARB states "it is estimated that currently 60-80 percent of UCO is processed using the technology employed representative of the data provided by an industry source, while the remainder is processed in cookers at rendering plants, such as those represented by Plants 1-7." The statement indicates that the "industry source" is not included with the other 7 rendering plants surveyed. It is not clear how data from all sources were handled. ARB should clearly indicate how data from the 7 survey rendering plants, the industry source, and the literature were used and weighted in deriving its carbon intensity values. Darling encourages ARB to develop the pathways for UCO based on the predominant process technology used by the rendering industry. Data from the seven plants surveyed should be ignored or properly weighted based on data obtained from a more inclusive survey of the rendering industry. (DARLING)

Response: Data provided were designated as business confidential and therefore complete details cannot be provided. The analysis did provide the final values that were used and the methodology was also described in the pathway document. In the updated pathway document for used cooking oil referred to in the response to Comment IV-84, staff considered two options for energy use for rendering: higher energy use based on older technologies (those that "cook" the UCO) and lower energy use (those that do not "cook" the UCO which was indicated to be the predominant process technology). The carbon intensity for rendering (and for the complete Well-to-Wheel) of UCO was calculated for both the options mentioned above.

IV-90. Comment: In the first paragraph on page 21, ARB discusses the assumption that half the UCO in the U.S. is processed via acid esterification and the other half is processed using a continuous, non-acid esterification. On what basis was this assumption made? Darling knows of little to any use of acid esterification. The only reason to use acid esterification is to treat free fatty acids in UCO in a two step biodiesel production process. Almost all biodiesel produced in the U.S. is produced using traditional transesterification (non-acid esterification), with free fatty acids, if any, removed prior to processing. (DARLING)

Response: The two methods described are utilized for the conversion of free fatty acids prior to the conversion of rendered UCO to biodiesel (a third method is proprietary and no commercial information is available about this method and its utilization). Based

on communication with an industry representative, a 50/50 split between the two methods was considered reasonable. What is to be noted here is that there has to be an energy (and hence a GHG) penalty to “clean” UCO prior to biodiesel conversion. This step essentially minimizes free fatty acids in the incoming feedstock before it is converted to biodiesel.

IV-91. Comment: If there are two different processes (transesterification alone or esterification followed by transesterification) used to produce biodiesel, one that uses more than twice the amount of energy than the other as stated by ARB in the first paragraph on page 21, then there should be two separate calculations for the energy and GHG emissions for the two different processes, rather than using an average of the energy required in the two different processes. Or ARB could determine which process is used in California, or develop a ratio based on the amount of biodiesel produced using each of the processes that could be used to determine an average energy usage. The importance of appropriately characterizing the process to be used to make biodiesel for California is supported by the fact that the energy required during biodiesel production is 18.45 percent of the energy required and represents 38.61 percent of the GHG emissions contributed to the Well to Tank calculation (Table A on page 4.) (DARLING)

Response: See response to Comment IV-90. In addition, the regulation includes Method 2A to allow producers to develop adjustments to published pathways where appropriate and supported by verifiable data and a rulemaking is conducted.

IV-92. Comment: ARB has made the assumption that the UCO is only originating in California and is being processed into biodiesel in California. This same assumption should also be made for Tallow. Darling is providing additional discussion on the availability of California origin Tallow in a subsequent comment under the renewable diesel section. (DARLING)

Response: The same commenter has requested that a stand-alone process for renewable diesel production be considered compared to the co-processed process assumed in the pathway document for the conversion of tallow to renewable diesel. As part of either Method 2A or 2B, appropriate feedstock transport distances could be developed for tallow produced in California.

IV-93. Comment: In Table 1.02 on page 11, ARB assumes that UCO is transported 50 miles from its place of origin to the rendering facility. Darling disagrees with including any calculations in the UCO pathway for direct energy use or upstream energy use associated with transporting UCO from its place of origin to the rendering plant for processing. Darling believes it would be inappropriate to include such energy calculations in this pathway. Fuel use and GHG production associated with transporting the raw UCO would not be avoided if these materials are not processed by a renderer or other UCO processor. In most metropolitan areas, disposal of UCO on-site, such as pouring UCO down the

drain, is prohibited. Therefore, if UCO is not collected and transported to a renderer, the restaurant would still find it necessary to have its UCO transported to a landfill or other disposal site. (DARLING)

Response: Staff reviewed this issue, and made appropriate adjustments to transport of UCO in the September 23, 2009 pathway document for UCO to biodiesel referenced in the final regulation.

IV-94. Comment: The calculations for Direct Energy and Upstream Energy on page 12 are very confusing. It would seem that the same calculation can be arrived at by simply multiplying the number of miles traveled by the truck times the Energy Intensity (Btu/ton-mi) factor found in Table 1.02 on page 11. However, the results of those two calculations are slightly different; 102,762 Btu/ton wet UCO, compared to 100 miles times 1,028 Btu/ton-mi equals 102,800 Btu/ton wet UCO. It would seem that the results should be the same since both approaches are calculating the amount of energy that it takes to move one ton of anything over a given distance. (DARLING)

Response: Due to rounding, the final values may be slightly different. The value 1,028 Btu/ton-mile is calculated from 25,690 Btu/mile /25 ton = 1,027.60 Btu/ton-mile. Note that for the final pathway value, the original values are preserved and the final value is presented without intermediate rounding.

IV-95. Comment: The Upstream Energy calculation should be the same as multiplying the Upstream Diesel Energy Factor (Btu/Btu) of 0.216 from Table 1.02 times the Direct Energy factor calculation of 102.726. However, the result of the formula presented in page 12 for Upstream Energy is 22,149, which is slightly different than 22,197 Btu/ton wet UCO obtained by multiplying the Upstream Energy Factor of 0.216 times 102,762. (DARLING)

Response: See response to Comment IV-94. The value of 0.216 is actually 0.21544. Note that for the final pathway value, the original values are preserved and the final value is presented without intermediate rounding.

IV-96. Comment: In both the Direct Energy formula and the Upstream Energy calculation, the energy and mileage for collecting UCD are repeated in the formula, which has the effect of doubling the energy used for transporting the UCO. There is no explanation provided for why the calculation is included in the formula. In the Direct CO₂ Emissions calculation on page 13, it is noted that the g/mmBtu is a factor used in the formula twice for travel by the heavy-duty trucks "both ways." This same note should be included for the formulas on page 12. The calculation or at least the rationale for the calculation may be based on a faulty assumption. Trucks used to collect UCO from restaurants typically stop at a number of different restaurants along pre-planned circuitous routes. Unlike other industries where trucks may drive some distance empty before picking up a load and returning, UCO collection trucks are only empty prior to the first stop

and load additional UCO with each subsequent stop going away from and returning to the plant. When asked distance traveled. UCO collection drivers usually report the distance for the entire route, leaving from and returning to the plant. As a result, doubling the energy mileage and emissions data in this pathway may be inappropriate and unnecessarily inflate direct and upstream energy calculations. (DARLING)

Response: Staff reviewed this issue, and made appropriate adjustments to transport of UCO in the September 23, 2009 pathway document for UCO to biodiesel referenced in the final regulation.

IV-97. Comment: References are not given for the origins of the GHG emission rates used in the calculations for GHG emissions from the Direct Emissions and Upstream Emissions shown in Table 1.06 on page 18. (DARLING)

Response: GREET uses EPA AP-42 emissions factors as inputs in the calculations of GHG emissions for various equipment and processes utilized in the various steps from feedstock production to final fuel consumption. Where appropriate for California, appropriate California applicable factors have been used (e.g. tailpipe emission factors for California as from EMFAC where available) in place of the original GREET emission factors.

IV-98. Comment: ARB does not identify how it arrived at the assumption for the transport parameters presented in Table 1.08 on page 19. (DARLING)

Response: See response to Comment IV-97.

IV-99. Comment: In the first paragraph on page 23, ARB states that it assumes the esterification input parameters used for soybean oil esterification are the same for biodiesel produced from UCO esterification. Is esterification frequently used to convert soybean oil into biodiesel? Did ARB research this assumption? If so, a reference should be cited. (DARLING)

Response: For UCO derived feedstock (post free fatty acids conversion), the production of biodiesel via transesterification is assumed to consume the same energy and GHG emissions as that from soy oil derived biodiesel. The process specifications were confirmed in consultation with a biodiesel stakeholder.

IV-100. Comment: In the fourth paragraph on page 2, ARB states that it has developed the pathway for a specific case of inedible Tallow sourced from rendering operations in the Mid-Western U.S. where the rendered product is then transported to California via rail. The assumption that only Tallow in the Midwest will be rendered and then shipped to California ignores the Tallow that is produced and rendered in California. (DARLING)

Response: See response to Comment IV-92.

IV-101. Comment: The pathway paper is written assuming that only Tallow will be used to produce renewable diesel. However, both Tallow and UCO can be used to produce renewable diesel. The document should recognize that renewable diesel can be made from either waste product. ARB may need to use two different pathways since the amount of energy required to process UCO prior to producing renewable diesel is lower than the energy requirements to render Tallow before producing renewable diesel from the rendered product. ARB will also need to develop a method for allowing blended UCO and Tallow processed together in a renewable diesel plant. (DARLING)

Response: The same commenter has requested that a stand-alone process for renewable diesel production be considered compared to the co-processed process assumed in the pathway document for the conversion of tallow to renewable diesel. Such pathways may be developed via Method 2B. As for facilities that process both feedstocks, producers may approach staff to consider the development of average intensities based on weighted feedstock processed annually (or other time period).

IV-102. Comment: Table 1.01 on page 13 provides rendering energy for production of Tallow. The data depicted is from 7 rendering plants, two of which ARB declares are located in California, and also from published thermal and electrical energy of a number of associations and research foundations. In the last paragraph on page 12, ARB states, "the average thermal and electrical energy use of the 7 plants was used as average direct energy use for the rendering process modeled in the pathway." This is inconsistent with the approach ARB used in the UCO pathway. Assuming that the source of data in the UCO pathway was the same as in the Tallow pathway, the use of the data should be consistent within the two pathways. (DARLING)

Response: This has been done in an updated release of the analysis for Tallow referenced in the September 23, 2009 Second 15-Day Notice. Staff considered two options for energy use for rendering: higher energy use based on older technologies and lower energy use for newer technologies. The carbon intensity for rendering (and for the complete Well-to-Wheel) of tallow to renewable diesel was calculated for both the options mentioned above. This will allow producers that utilize newer technologies to use the lower carbon intensity provided it is supported by verifiable data.

IV-103. Comment: The survey data in Table 1.01 represents only seven plants and does not appear to be collected using a statistically significant methodology. The data from the lowest energy user to the highest energy user is almost double what is reported by the lowest plant. The energy used during the rendering process is heavily influenced by the type and quality of the raw material being processed. Energy used to produce a pound of tallow from the offal derived from the slaughtering process will typically be lower than for tallow derived from rendering animal mortalities. Some rendering operations process a mixture of these materials in addition to meat market waste. The energy required to

produce a pound of tallow in such facilities will be intermediate to plants processing offal and those that primarily process mortalities. ARB should conduct a statistically significant sample of data using a third party source to protect the proprietary nature of the data to measure and address this apparent diversity in energy usage among different rendering operations in the industry. For example, data could be collected through the Pacific Coast Renderers Association to obtain data for rendering plants in California. Similarly, a national renderers association, such as the FPRF or the National Renderers Association, may be used to obtain data for U.S. renderers outside of California. Darling would participate in such surveys, provided Darling can be assured, to its satisfaction that its anonymity and the confidential nature of its data can be protected and such data will only be used to develop industry averages. (DARLING)

Response: See response to Comment IV-102. As for updated industry averages, when such information becomes available, appropriate refinements will be considered.

IV-104. Comment: Table E on page 8 shows GHG emissions associated with Tallow transportation to the renewable diesel production plant; however, the units in the table are Btu/ton Tallow. It would seem that the emission rate should be expressed as a weight such as grams/ton Tallow or lbs/ton Tallow. The totals in the table are given in g CO₂e/mmBtu. (DARLING)

Response: Staff acknowledges the error and it has been corrected. It does not affect the final calculations or results.

IV-105. Comment: In the first paragraph of Section 1.3 on page 18, ARB states that the U.S. average regional parameters are used in CA-GREET for Tallow transport. What is the reference for the parameters? (DARLING)

Response: Average regional parameters are based on information pooled from several sources such as MOBILE6 (EPA), AP-42 truck capacity data from truck manufacturers, rail carrying capacity from railroads, etc. See also response to Comment IV-97.

IV-106. Comment: In the first paragraph in Section 1.4 on page 16, ARB states that the analysis assumes 10 miles for heavy-duty truck transport and 1,400 miles rail transport to the fuel production facility in CA. Does ARB assume that the Tallow is transported 10 miles to the rail transport, and the rail transport delivers the Tallow directly to the fuel production facility in CA? As previously discussed, rail transport of this distance is not necessary for Tallow produced by renderers in California and assuming all Tallow is transported this distance unjustly penalizes California renderers. (DARLING)

Response: The assumption is 10 miles from tallow collection point to rail stations followed by 1400 miles from Midwest to California for this specific pathway. For

California producers, this can be reviewed under Method 2A. (See also response to Comment IV-101)

IV-107. Comment: Darling agrees with ARB that there should not be any calculation for direct energy use or upstream energy use for transporting the animal by-products from their place of origin to the rendering plant. Fuel use and GHG production associated with transporting the raw animal by-products would not be avoided if these materials were not rendered. If not transported to a renderer, the packing plant or meat processor would still find it necessary to transport these slaughter and trimming wastes to a landfill or other disposal site. (DARLING)

Response: This is the approach used by staff in the pathway analysis for tallow to renewable diesel.

IV-108. Comment: In Table 1.02 on page 14, the input for electricity is labeled as "Electricity (U.S. Average) (Btu/lb)." In the UCO pathway, in Table 1.06 on page 17 the input for electricity is labeled as Electricity (CA marginal) (Btu/lb UCO). The tables are similar in that they show the direct energy upstream energy and total energy, but either the labeling is inconsistent or the source of the data is different. (DARLING)

Response: The tallow is assumed to be rendered in the Midwest plants, which use U.S. Average Electricity, while the UCO is assumed to be rendered in CA using CA Marginal Electricity.

IV-109. Comment: What is the source of the GHG emission rates used in Table 1.06 on page 17? (DARLING)

Response: See response to Comment IV-105 above.

IV-110. Comment: In Table 2.01 on page 19, what are the references for the Fuel Shares used in the calculations? (DARLING)

Response: As stated in the beginning of the first paragraph page 19 of the September 23, 2009 version of the Biodiesel from UCO pathway document, the values of fuel shares are calculated from the assumption of 3.8 percent by weight of hydrogen is used in the process. Argonne National Laboratory had released a technical report to support the GREET model (ARGONNE Technical Report: "Life-Cycle Assessment of Energy and Greenhouse Gas Effects of Soybean-Derived Biodiesel and Renewable Fuels" (December 2008) – M. Wang et al.), where 0.032 pound hydrogen, 93.83 Btu electricity, and 84.05 Btu natural gas used to produce 1 pound of renewable diesel. This converts to percentages as stated in the document.

IV-111. Comment: What is the source of the assumptions used in the second paragraph of Section 3.1 to determine 80 percent of renewable diesel is

transported 50 miles to the bulk terminal, and 20 percent of the renewable diesel is distributed directly from the refining plant? (DARLING)

Response: The 80 percent of 50 miles transport to blending terminal and 20 percent at terminal is based on an assumption used in the AB 1007 analysis. This was used since actual renewable diesel facilities are non-existent and to calculate energy use and GHG emissions, a reasonable value is necessary in the model. These values were considered to be reasonable for California. Small changes in the miles transported usually have relatively small impacts on total Well-to-Wheel emissions.

IV-112. Comment: What is the source for the assumption that renewable diesel is transported 90 miles from the bulk terminal to the refueling stations? (DARLING)

Response: This is a combination of 50 miles from blending terminal to final distribution (100 percent) and the 80 percent of 50 miles = 40 miles from the earlier step from refinery to blending terminal. CA-GREET uses one composite input for T&D. See also response to Comment IV-111.

IV-113. Comment: In the Tallow pathway, the system that ARB has analyzed has not included the co-products from the rendering process and this oversight can have a significant impact on the emissions. (NBB2)

Response: The energy for rendering and consequently the associated GHG emissions was considered only for the tallow produced and not for the meat and bone meal that is produced as part of the rendering process. The energy was proportionally allocated as detailed in the September 2009 update. The numbers in the Lookup Table have been corrected.

IV-114. Comment: The energy consumed in the rendering process should be allocated between the two products, the tallow and the meat and bone meal. ARB has used energy allocation in the soybean pathway to allocate between the products and the same approach could be used here. The energy content of the tallow will be very similar to that of soy oil, 16,000 BTU/lb (37,333 MJ/kg) as used in the GREET model. (NBB2)

Response: The energy represents only the energy for rendering tallow and not for the meat and bone meal that is produced as part of the rendering process. The energies have been proportionally allocated between the two products. This has been stated in the September 23, 2009, Renewable Diesel from Tallow document.

IV-115. Comment: In the Tallow pathway, the energy content of meat and bone meal will vary with the feedstock mix. The final product can have varying moisture and ash contents, which will impact the energy content. Denafas et al reported energy contents from 15.7 to 18.1 MJ/kg for meat and bone meal from five different European countries. Using a mass ratio of 60 percent oil and 40 percent meal from the rendering process, the energy ratio of the products will

be 77 percent allocated to the oil and 23 percent allocated to the meal. This would lower the emissions for the tallow production stage by 3.9 g/MJ. The lifecycle emissions for the tallow renewable diesel fuel would be reduced to 25.8 g/MJ. (NBB2)

Response: This was resolved in the September 2009 release of the revised Renewable Diesel from Tallow pathway document and the numbers in the Lookup Table reflect this.

IV-116. Comment: In the Cooking Oil pathway, the report shows that the GHG emissions for this pathway are 13.70 g CO₂eq/MJ of fuel. This represents an 85 percent reduction compared to the reference diesel fuel. ARB has determined that there are no indirect land use emissions associated with this fuel. The pathway is relatively simple and ARB has generally done a good job in identifying the relevant inputs into the process that are required for modeling purposes. The NBB did supply ARB with the results of their Energy Survey of producing members but it does not appear that these were taken into account during the development of this new pathway. (NBB2)

Response: The survey does not provide adequate details on how the reported energy use was calculated. In addition, it may not include all the plants currently in operation. The regulation includes Method 2A to allow individual producers to modify existing pathways based on producing verifiable data following a rulemaking

IV-117. Comment: There are two issues that the NBB have raised before with respect to the biodiesel pathways that remain unresolved in Cooking Oil pathway. These are the quantity of glycerin produced, which impacts the allocation of energy and emissions in the system, and the allocation of biogenic carbon in the system between biodiesel and glycerin. (NBB2)

Response: See response to Comment IV-115.

IV-118. Comment: The GREET model has mass balance for biodiesel production that is based on the NREL biodiesel LCA that was undertaken during the 1990s. The model assumes that the quantity of glycerin that is produced is 21.3 percent by weight of the quantity of biodiesel produced. This value is incorrect, both from considering the stoichiometric ratio for the biodiesel reaction and from the industry experience. (NBB2)

Response: See response to Comment IV-115.

IV-119. Comment: The impact of the error in the ARB documents is small and it results in an underestimation of the GHG emissions for all biodiesels. When it is eventually found, it will reduce the credibility of the significant reduction in GHG emissions that are provided by biodiesel fuels. It is very easy to correct this

values in GREET. Cell C39 on the BD sheet needs to be set to 0.10 instead of 0.213. (NBB2)

Response: See response to Comment IV-115.

IV-120. Comment: The approach used here of proportioning the carbon in biodiesel between biological and fossil really needs a similar calculation to be undertaken for the glycerin and a credit added back to this system in order to portray an accurate picture of the GHG emissions. It is recommended that California take the same, simplified approach as used by other models (and the standard GREET model) and assume that all of the carbon in the biodiesel is biological and all of the carbon in the glycerin is fossil. This would reduce the GHG emissions associated with biodiesel by 3.7 g/MJ. If the rationale is that there is a greater chance that glycerin from used cooking oil might not be fully utilized as a displacement product for fuel or synthetic glycerin, then perhaps the option is to report two values for biodiesel fuels, one that would be applicable to facilities that waste the glycerin and a second value for plants that utilize the glycerin as a feedstock to replace synthetic glycerin or fuel use. This alternative approach would provide equity to all biodiesel producers and should provide an incentive for plants to optimize the utilization of the glycerin. (NBB2)

Response: The analysis presented for biodiesel production from UCO includes impacts of fossil carbon in biodiesel derived from reactants used in the production process (carbon from soybean oil is considered as carbon neutral and not assigned a GHG value). This is accordingly accounted for in the analysis. Similarly, when an updated biodiesel from soybean oil pathway is published for public comments, the same impacts of fossil carbon in biodiesel will be maintained.

IV-121. Comment: Page 44, §95486(b)(1) Table 7. It is good that the Carbon Intensities in Table 7 are draft values. ARB is urged to adjust the carbon intensities for renewable diesel to reflect our comments on the individual pathways for renewable diesel. Specifically we are asking ARB to:

1. Reduce renewable diesel's Tank to Wheel gCO₂e/MJ to reflect renewable diesel's lower NO_x and THC emissions.
2. Reduce renewable diesel's Transport & Distribution energy consumption and gCO₂e/MJ emissions to reflect the fact that renewable diesel will be distributed like ULSD. For renewable diesel produced in commingled processes the Transport & Distribution numbers should be identical to those of ULSD because the hydrotreater products are comingled. For renewable diesel produced in separate processes, the optimum blending location is at refineries. Therefore, its transport and Distribution factors should be the ULSD Transport and Distribution numbers plus some Transport & Distribution factors to move the renewable diesel from its processing facility to the typical blending refinery.

3. In the draft pathways for biomass based diesels from soy we noticed inconsistent treatment of the renewable propane and glycerin co-products. To eliminate this inconsistency we are recommending that the net energy and gCO₂e/MJ benefits of the co-products be allocated to the biomass-based diesel products. This is a reasonable because:

- a. The GHG benefits of the co-products are real.
- b. The biomass based diesel production caused the renewable co-product production. Thus, the GHG benefits belong to the biomass based diesel.
- c. Allocating the net fossil propane or glycerin offsets to biomass-based diesel more accurately reflects the full GHG benefits of the biomass based diesel lifecycle.
- d. Doing so simplifies both the regulatory and enforcement process by eliminating the need to develop complex tracking and enforcement regulations for a relatively small volume of renewable fuel that is chemically identical to fossil based molecules.
- e. Improves the material balance for the pathway.
- f. Consistent treatment of co-products increases the credibility of lifecycle analyses.

4. The renewable diesel from Tallow pathway assumed the maximum hydrogen consumption per unit of product. The average of the minimum and the maximum consumption rates would be more accurate than either extreme. Please rerun the case with a more reasonable hydrogen consumption assumption.
(A204NESTE3)

Response: The Well-to-Wheel analysis does not include impacts from NO_x though THC_s from the production processes are accounted for in the analysis. Any specific advantages for renewable diesel can be determined when significant test data becomes available. Currently, there is a test program underway at ARB that could provide valuable data. The pathway document was derived for an analysis of 100 percent renewable diesel to allow appropriate calculations to be performed based on per MJ of renewable diesel. The co-products for both biodiesel and renewable diesel pathway have been provided appropriate co-product credits using energy allocation. Only a proportional amount of energy (and attendant GHG emissions) used for producing the biodiesel (or renewable diesel) is allocated in the analysis. For specific cases where lower hydrogen utilization is warranted, producers may approach staff utilizing Method 2A to develop a specific pathway for their process.

IV-122. Comment: In our comments on the renewable diesel from Tallow pathway we calculated an approximate impact of items 1, 2 & 3 on both the renewable diesel

from Tallow and renewable diesel from Soy pathways. We did not calculate the impact of the hydrogen assumption nor did we calculate estimates for the impact on the biodiesel pathways. Because the glycerin yield is so much larger than the propane yield we anticipate the impact of item 3 will be much greater on the biodiesel pathways than it was on the renewable diesel pathways. While item 3 will cause there to be some fossil carbon emissions in the biodiesel Tank to Wheel emissions, the overall net impact will probably be favorable for biodiesel. Because this methodology will increase the net energy produced per acre of soybeans, the Indirect Land Use Change in gCO₂e/MJ will decrease. For example if the draft ILUC for renewable diesel from soy was 40 g CO₂e/MJ, it should be about 35 g CO₂e/MJ with these corrections. (A204NESTE3)

Response: The soy pathway is not complete and its land use change analysis is being refined at this time. As noted in Section I.A., ARB plans to make available for comment the completed pathway document and the carbon intensity value for soy biodiesel in the near future, and to adopt the carbon intensity value as part of this rulemaking by February 2010. The suggestions made by this commenter are being considered in the development of the pathway document.

IV-123. Comment: Pages 48 & 50 §95486(c) & §95486(e)(2)(A) Substantiality. We understand the need for something like "5-10" substantiality. Without it, ARB staff would be even more overworked or ARB would have to charge very high fees for all type 2A and 2B pathway petitions. However, we would like to recommend one modification, 5 gCO₂e/MJ is probably acceptable for pathways with carbon intensities greater than 50; but when pathway carbon intensities fall below 50, we should consider a 10 percent improvement to be substantial. I raise the question not because I want ARB to consider a 4 carbon intensity improvement for a pathway with a 40 carbon intensity but because I do not want ARB to inadvertently stop research and development on ways to reduce carbon emissions of processes that have pathway carbon intensities of 25. Engineers are good at making things work better in small increments. When those little pieces add up to 8 or 9 percent, they will look very hard for the last 2 or 3 percent to get across the threshold. However, if the threshold is 20 percent they are more likely to stop looking and to not implement the small improvements. If Global Warming is a real problem, we cannot afford to stop R&D on a process because it is better than its competitors or good enough. If we can afford to stop R&D, then we do not need the Low Carbon Fuel Standard. (A204NESTE3)

Response: The rationale for the 5 grams is to be able to have changes that are substantial, quantifiable, enforceable, and verifiable. Considering the values that we estimated are not absolute, in that uncertainties exist, and as a result determining when improvements occur is difficult when the improvements are small.

IV-124. Comment: The commenter "A 2nd Opinion Inc." voiced concerns on the Detailed California-Modified GREET Pathway for Renewable Diesel Produced in

California from Tallow (U.S. Sourced) July 20, 2009 draft. The commenter has pointed to:

Pages 2 & 24: The assumption "Combustion of renewable diesel in a heavy-duty vehicle is assumed to generate the same CH₄ and N₂O emissions as ULSD." is not accurate. The exceptionally high hydrogen content (paraffin composition) and distillation properties of renewable diesel cause renewable diesel to emit less NO_x and THC than typical ULSD when burned. ARB should update this assumption. Using estimated properties of commingled renewable diesel, typical ARB ULSD properties and EPA's Unified Model, we find we can attribute a 14 percent reduction in NO_x emissions and a 37 percent reduction in THC emission to renewable diesel¹⁰⁰. This reduces the g CO₂e/MJ for combusting renewable diesel from the assumed 0.78 to 0.66 g CO₂e/MJ. This is not a big number. It is well below the accuracy of lifecycle GHG calculations. But, it belongs to the clean fuel and should not be lost due to a simplifying assumption. We anticipate that when ARB completes the Biodiesel and Renewable Diesel Research Study they may want to replace the Unified Model results with the new data. You will however need to correct for the actual test CARB ULSD being slightly cleaner than the average CARB ULSD.

Page 3: Concerns about bovine spongiform encephalopathy could also make edible tallow a waste product. ARB will need to monitor the issue.

Pages 5, 9, 10, 21, 22 & 23: The renewable diesel Transport and Distribution assumption is wrong for 2 reasons:

1. This is a comingled production process. That means that renewable diesel has to be distributed with ULSD and therefore, just like ULSD.

2. Regulatory analyses of fuels programs are typically based upon optimized systems. renewable diesel has greater value and lower distribution costs when blended at the refinery level. Its optimum blending location is at the refinery level. For comingled renewable diesel transport and distribution is identical to that of ULSD. For separate processing train renewable diesel there could be a transport and distribution component to get the renewable diesel to a refinery for blending in addition to the ULSD transport and distribution factors when the renewable diesel facility is not adjacent to the blending refinery. Therefore, based upon the "Detailed California-Modified GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California" dated February 29, 2009 the Renewable Diesel Transport and Distribution numbers for the comingled renewable diesel should be 4721 Btu/mmBtu renewable diesel and 0.33 gCO₂e/MJ renewable diesel, not 8,662 Btu/mmBtu renewable diesel and 0.66 gCO₂e/MJ renewable diesel as shown in Table A of the draft.

Page 5: Because 0.059 lbs of renewable propane (RP) is produced for every lb of renewable diesel a table that is similar to Table A can be created to calculate a fossil propane credit based upon the renewable propane production less the energy and carbon emissions allocated to the co-product. To make it easier to

see the basis of the numbers the Energy Required is based upon 1,000,000 Btu renewable diesel and the CO2 Emissions are based upon one MJ of renewable diesel. (A204NESTE4)

Response: A test program is currently underway at ARB that is testing renewable diesel in engines and heavy-duty vehicles. The Well-to-Wheel analysis does not include impacts of NOx but includes all GHGs considered by the CA-GREET model. Staff is assessing the impacts of FDA regulations related to BSE and use of animal by-products in animal feed industry. The pathway document was derived for an analysis of 100% renewable diesel to allow for appropriate calculations to be performed on the basis of per MJ of renewable diesel. Any refinements to transport could be considered as information becomes available and modifications can be made under Method 2A. It should be noted that impacts from local transportation are usually small. The co-product propane for the renewable diesel has been provided an appropriate co-product credit using energy allocation. Only a proportional amount of energy (and attendant GHG emissions) used for producing the renewable diesel is allocated in the analysis.

IV-125. Comment: While UNICA is pleased that ARB has recognized several of our recommended changes on the “direct” lifecycle calculations, we are concerned about the delays in addressing the “indirect” land use change component of the calculations for the LCFS. We strongly urge ARB to act quickly in addressing the numerous concerns we – as well as a number of other stakeholders – have raised with regards to accuracy of ARB’s calculations of the indirect effects of biofuels production. The alleged “indirect” land use change penalty, currently set at 46 gCO2/MJ by ARB, is nearly four times greater than the “direct” lifecycle of sugarcane ethanol as calculated by the staff in the proposed new pathways. (UNICA2)

Response: Based on concerns raised by producers, the Board, in Resolution 09-31 approving the LCFS, directed staff to establish an Expert Working Group to refine the current analysis for land use change along with related issues and report to the Board by December 2010. Based on the recommendations of this group, appropriate refinements will be considered.

IV-126. Comment: We have previously commented on many aspects of the developing regulation and will not re-raise those issues here. The focus of these comments is to address the ARB’s “Detailed California-GREET Pathway for Renewable Diesel from Tallow” dated July 20, 2009. We recommend clarifying language regarding the description of tallow (page 2 of the document). Tallow is beef fat produced during byproduct rendering. There are various grades of tallow. Those commonly referred to as technical and inedible tallow are the primary feedstocks used in this fuel pathway. The rendering of technical and inedible tallow involves different equipment and sources of energy. Technical tallow refers to that material rendered from trim fat and bones during animal processing. The technical rendering process includes grinding of the trim fat and bones, applying heat, and centrifuging to separate the fat from the solids and water. Technical

tallow is qualified as edible tallow if a U.S. Department of Agriculture (USDA) inspector inspects the process. Inedible tallow rendering involves grinding and cooking of the animal byproducts (viscera, hooves, head, and other waste materials), evaporating water off through extensive heating (water content can be up to 60 percent by weight), and separating the fat from solids through screening and centrifuging. The rendering of inedible tallow is more energy intensive compared to that of technical tallow.” (CONOCO2)

Response: The analysis for rendering allocates proportionally the emissions for meat, bone meal, and tallow. The analysis presented in the pathway document considers only inedible tallow. For the special designated category “technical tallow,” producers can develop a modified pathway utilizing Method 2A.

IV-127. Comment: We also recommend the following clarifying language under the “note” item that appears on page 3 of the document. “Note: Removal of tallow for renewable diesel production from the market may lead to replacements for tallow in industries where it could have been traditionally used. It is important to note that cattle are not grown and processed for the purpose of generating tallow (rather they are grown and processed for meat). In terms of replacing tallow in current markets, according to USDA data, the majority of waste oils and tallow processed in the U.S. are used as animal feed. Future regulations may apply a ban on the use of tallow and other animal-based waste products (due to mad-cow and other similar diseases) for animal feed. It is likely that the use of inedible tallow as supplements in animal feed will diminish in the future. In addition, because of RFS2, USDA reports a growing amount of supply to the animal feed market resulting from increased production of DDG’s, soymeal, etc. Based upon the above considerations, any indirect effects from diverting tallow from the animal feed market to manufacturing renewable diesel should be very small or insignificant regarding GHG impacts. That said, staff will continue to assess the unintended effects of removing tallow from the market for renewable diesel and will make appropriate adjustments to the analysis if warranted. (CONOCO2)

Response: Staff appreciates the comment and will consider the information when considering future pathways for tallow to diesel.

IV-128. Comment: We compared the energy consumption data in Table 1.01 to other values obtained from published literature. Our finding was that published data refer to total energy input in the rendering process, not for the production of inedible tallow alone. This suggests that the energy consumption data and GHG emissions in the rendering process have not been properly allocated between MBM and inedible tallow. Our conclusion is that the total GHG emissions for the tallow renewable diesel pathway are overestimated. A second issue related to Table 1.01 is the unit of measure (BTU/gal). It is unclear if the unit is BTU/gallon to produce a gallon of biodiesel or a gallon (equivalent) of tallow; please clarify. (CONOCO2).

Response: The energy for rendering and consequently the associated GHG emissions were considered only for the tallow produced and not for the meat and bone meal that is produced as part of the rendering process. The energy was proportionally allocated as detailed in the September 2009 update. The BTU/gallon refers to a gallon of biodiesel.

IV-129. Comment: Address our concerns with using co-processing of Tallow with crude oil for its Tallow to renewable diesel pathway. Darling recommends using a dedicated hydro-treating facility that produces a pure renewable diesel that is suitable for use neat or for blending with petroleum diesel. (DARLING).

Response: In Resolution 09-31, the Board directed the Executive Officer to work with biofuel producers and other interested stakeholders to identify specialized fuel pathways such as anaerobic digestion, thermochemical conversion of biomass feedstocks and additional liquefied natural gas pathways that the Board staff will develop and propose for incorporation into the Carbon Intensity Lookup Table. The prioritized list, with a proposed development schedule, shall be presented to the Board by December 2009. Additionally, there is a mechanism (Method 2B) in the regulation to create a pathway as detailed in the comment if this list does not included the tallow pathway.

IV-130. Comment: Our final comments relate to co-product allocation issues regarding the use of tallow for renewable diesel production. The animal rendering process produces tallow (technical and inedible) as well as an animal feed supplement called meat and bone meal (MBM). Technical tallow is produced using a different set of procedures and equipment. Inedible tallow and MBM should be considered co-products in the analysis. The ratio of MBM to inedible tallow is approximately 7 to 3 by weight. Therefore, the total energy input and the associated GHG (GHG) emissions should be allocated between MBM and inedible tallow. It is unclear in the ARB document how the allocation was handled. For example, Table 1.01 presents the average energy consumption of inedible tallow rendering from seven processing facilities, which includes 28,813 BTU/gal thermal energy and 0.930 kWh/gal electricity. The associated GHG emissions for inedible tallow production (18.19 g CO₂e/MJ) were estimated based upon these numbers. (CONOCO2)

Response: The analysis for rendering allocates proportionally the emissions for meat and bone meal, and tallow. The analysis presented in the pathway document considers only inedible tallow. For the special designated category “technical tallow,” producers that can document exclusive of technical tallow can develop a modified pathway utilizing Method 2A.

IV-131. Comment: Let me say, however, that the model for SOY-Biodiesel is fundamentally flawed in that a substantial portion of the calculated energies and emissions incurred upon biodiesel production are erroneously credited BACKWARDS to soy meal as a by-product. This credit was already taken at the farming, seed transport, oil extraction, and oil transport steps. It is unfair to credit

this pathway again with further allocations to this by-product. The UCO-Biodiesel models (both GREET and SPT) are handled properly in this matter. (SPT2)

Response: The soybean biodiesel pathway is being modified and an updated pathway document will be published for public comment as discussed in the response to Comment IV-122. The concerns expressed in this comment are being considered in the updated analysis.

IV-132. Comment: You also neglect to show details of your assumed biodiesel manufacturing process. You don't specify whether the process allows for stripping of methanol/water out of the by-product glycerin, nor does it specify whether the model allows for distillation and recovery of wet methanol. Note that these are BIG omissions that affect the credibility of your models for both SOY-based and UCO-based biodiesel.

Nevertheless, I did a bit of reverse engineering using your implied mass and energy balances, and I am convinced that you DO NOT include energies and emissions from processing of glycerin and recovery of methanol. This is not only disingenuous, but in a subtle way, it gives double-advantage to the standard biodiesel model. It not only ignores these processing energies and emissions at the biodiesel production step, but it goes further to *credit* the biodiesel production processes with a larger by-product "off-set" allocation due to the fact that the crude glycerin mass and energy content is increased by its methanol content. (SPT2).

Response: The analysis for this pathway was conducted using industry average production processes as detailed in the Argonne model. The methodology is to account for all energy and emissions from the production process (inclusive of any recovery steps). The pathway detailed being industry average for biodiesel production captures all the energy and emissions for the production of biodiesel from soybean oil. As for glycerin production, a recent version of UCO to biodiesel pathway document made the appropriate adjustment for glycerin produced. This will be the same methodology used when staff updates the soybean oil to biodiesel pathway.

IV-133. Comment: The allocations to renewable diesel for tallow production, transport and conversion to renewable diesel are simply the total energy and carbon emissions for each step less the amount allocated to renewable diesel. Because the propane co-product will either be converted to hydrogen or fuel gas on site no distribution energy or carbon emissions should be attributed to it. Producing 1,000,000 Btu of renewable diesel results in the coproduction of $(1000000/18925 \times 18568 \times .059)$ or 57,887 Btu of propane. Producing 1 MJ of renewable diesel results in the co-production of 0.002954885 lb of renewable propane $(947.817/18925 \times .059)$. This displaces fossil propane that would have released 4.02 gCO₂e $(947.817/18925 \times 0.059 \times 454 \times 36.033/44.097 \times 44.009/12.011)$ when either burned or used as hydrogen plant feedstock. (A204NESTE4)

Response: The propane that is produced during the production of renewable diesel is provided a co-product credit. This is from an energy allocation methodology where not all the emissions for the production of renewable diesel are attributed to renewable diesel but lower by a proportion that is attributable to the propane co-product. For the specific cases of propane being used as a feedstock for hydrogen production or burned, modifications via Method 2A can be pursued.

IV-134. Comment: In the first paragraph on page 15, ARB states that when UCO is processed in a facility that also renders animal by-products, the water or moisture in the UCO is removed using cookers. In addition, ARB states that since UCO contains much less moisture than animal by-products, cooking off the UCO moisture is less energy intensive. These statements imply that the two raw feed materials, UCO and animal by-products, are either processed together or that rendering plants processing both UCO and animal by-products use cookers to eliminate the moisture from UCO. In the rendering industry, UCO is seldom added to the cooking process used for rendering animal byproducts unless it is used in place of Tallow to charge the cooker at the beginning of a production cycle. Rather, UCO is processed separately from the animal by-products by using a decanting process, which requires much less energy. (DARLING)

Response: The average of the data collected and reported for seven different plants for this study are based on several older rendering plants in the U.S., which process UCO in their cookers. ARB believes this is currently representative of biodiesel produced from UCO. The pathway analysis presented in July considered only UCO being rendered in “cookers.” Based on comments received, staff revised the analysis for rendering and provided two scenarios: higher energy use for rendering (such as by cooking) or lower energy use (no cooking as may be likely in newer plants). Both the scenarios consider only rendering of UCO and do not include co-mingled feedstocks (UCO, animal by-products, etc.).

IV-135. Comment: In the second paragraph on page 15, ARB states that the data collected and reported in Table 1.05 on page 16 is from inquiries conducted with seven U.S. rendering plants. The results of those inquiries show that for those seven plants the energy used for processing varies by an order of magnitude. In addition, ARB states that the difference in energy requirements may be due to the way UCO is processed and the moisture content of the unprocessed UCO. In the third paragraph, ARB states that it takes a lot less energy to decant the UCO than it does to cook the UCO. In the fourth paragraph on page 15, ARB provides a rationale for using a thermal input number that is estimated by the Fats and Proteins Research Foundation (FPRF). The selection and use of that thermal number for processing UCO is troubling because of the rationale provided by ARB in the paragraph. There is no explanation as to how the FPRF arrived at its estimated thermal input number and the reference to the material used to determine the energy requirement is very vague. ARB chose the number because “it is close to the weighted average of Plants 1-7 in Table 1.05 and the data provided by an industry source.” The data collected for Plants 1-7 do not

appear to have been collected using a statistically significant methodology. “It differs by an order of magnitude.” ARB should conduct a statistically significant sample of data using a third party source to protect the proprietary nature of the data. ARB should collect data that provides specific information concerning the method used by renderers to process UCO, and data concerning estimates of the energy used to process UCO as well as energy estimates for processing animal by-products. For example, data such as this could be collected through the Pacific Coast Renderers Association. Darling would participate in such a survey, provided Darling can be assured, to its satisfaction, that its anonymity and the confidential nature of its data can be protected and such data will only be used to develop industry averages. (DARLING)

Response: The data provided to staff were classified as business confidential. The analysis used the average from this set and compared it against publicly available information. This provided a justification for using an average energy use for rendering of UCO as was done in the July pathway analysis. Based on comments received on the likelihood of lower energy use for UCO rendering, staff revised the Lookup Table to include two sets of pathways for rendering of UCO: higher and lower energy use based on the type of rendering operations performed. Producers that use the lower energy pathway can utilize this pathway provided they can support the pathway information with verifiable data.

IV-136. Comment: In the first paragraph of Section 2.1 on page 18, ARB states that “renewable diesel can be produced using many different methods and process configurations within a refinery,” and ARB chose a “co-production” process with crude oil. Why did ARB choose this method rather than one of the many other ways and configurations? Darling disagrees with the approach of using co-processing as the first California GREET pathway for the conversion of Tallow to renewable diesel. (DARLING)

Response: The analysis presented one likely pathway for the conversion of tallow to renewable diesel. In cases where a producer can demonstrate processes or practices, which result in lower carbon intensity for its fuel, Method 2A can be used.

IV-137. Comment: Darling does not believe that co-production with crude oil will be a viable method for the production of renewable diesel because of financial and process related issues. Fuels made when UCO and/or Tallow are co-processed with crude oil no longer qualify as renewable diesel. Thus, such fuels are ineligible for the \$1.00 per gallon renewable diesel credit (but may qualify for the \$0.50 per gallon alternative fuel mixture tax credit through the 2009 calendar year). According to legislation passed by the U.S. Congress, renewable diesel cannot be produced from co-processing a feedstock derived from biomass, such as Tallow, with feedstocks not derived from biomass such as petroleum products. (DARLING)

Response: The analysis presented one likely pathway for the conversion of tallow to renewable diesel. Considerations such as changes in federal mandates were not accounted for when this pathway was developed. We understand that market economics drive production of new fuels and there exist mechanisms (Method 2A and 2B) in the regulation where a producer can revise an existing pathway or create a new pathway such as the one mentioned above provided it can be supported by verifiable data and a rulemaking is conducted.

IV-138. Comment: UCO and Tallow contain impurities, which de-activate the catalysts commonly used by the petroleum refinery industry; also higher yields can be obtained with catalyst specifically selected for the processing of Tallow or UCO feedstocks. Further handling of commercial quantities of fats, either virgin oil, UCO or Tallow, will require separate and dedicated facilities for receiving and pre-treatment before these fats can be processed. (DARLING).

Response: ARB believes that the revised pathways modeled are representative of renewable diesel produced from tallow and biodiesel from UCO. For tallow feedstock, the co-processing energy and hydrogen requirements are considered to include both preparation and conversion of this feedstock. As for dedicated handling facilities, a WTW analysis considered here does not account for facility setup but only the energy used in transporting and converting a feedstock into a transportation fuel. These concerns may lead to dedicated facilities to produce renewable diesel. For dedicated facilities, a new subpathway will need to be developed. As mentioned in the response to Comment IV-129, staff will be developing a prioritized list of pathways for development in 2010. In addition, fuel producers can use Method 2A to establish a new subpathway.

IV-139. Comment: Finally, renewable diesel has superior properties to petroleum diesel and when produced separately, can be mixed with lower cetane blendstocks. Hence, Darling believes that most renewable diesel production will take place in facilities designed specifically to hydrotreat and isomerize virgin oils, UCO, Tallow or blends of these materials, and accommodate the oxygen and other sour gases that are released during processing. Such dedicated hydro-treating facilities may be located within, near or adjacent to an existing crude oil refinery. Further, hydro-treating involves exothermic reactions. ARB should verify that it has included the energy savings that result when excess heat from these reactions is recovered and re-used elsewhere in a refinery. (DARLING).

Response: The pathway for renewable diesel is for co-processed feedstock. As this commenter has indicated elsewhere, they would prefer to create a pathway for renewable diesel from a stand-alone process using tallow, UCO, etc. Method 2A in the regulation will allow for the creation of a separate subpathway. Process refinements suggested here could be considered during the development of this subpathway. See response to Comment IV-138.

IV-140. Comment: Tesoro understands that waste oil and tallow are primarily used as animal feed. However, if these materials are upgraded to motor fuels, the current consumers of these oils will need to replace them with some type of feed – possibly distiller’s grain with solubles (DGS). The resulting CO₂ emissions from making those replacement materials represent the GHG cost of taking waste oil and tallow to motor fuel feed stocks. We currently know the GHG “value” of DGS since it receives a credit as a byproduct of making ethanol. It is not correct to assume, as ARB has done, that the GHG cost of these materials is zero. ARB argues that these materials are “waste products,” so turning them into motor fuels does not incur any GHG “cost” for the feed stocks. If this is true, a refiner should be able to process fuel oil (arguably a waste product from the refining process) into gasoline and claim that the combustion of the gasoline has no GHG emissions. However, this is not the case – neither feedstock should be considered to have zero GHG “costs” as feedstocks. The guiding principle should be ARB’s correct methodology to fully account for byproducts. The waste oil and tallow pathways should include a GHG cost for the feedstocks. If these oils are taken from animal feed and are replaced with DGS, the GHG cost would be equal to the GHG value of DGS as a byproduct of producing ethanol. (TESORO3)

Response: New regulations being developed by USFDA are expected to prohibit the use of tallow as animal feed. In fact, this change is already occurring and almost all biodiesel in California is produced from these feedstocks. As discussed in the final fuel pathway documents for inedible tallow and waste oil, today feedstocks are considered to be waste materials from the meat processing and oil use industries. If additional data or information is provided that indicates that these waste materials have indirect effects, they will be considered and additional pathways will be developed.

IV-141. Comment: Several of us in this engineering office have independently reviewed the ARB UCO-BD document, and have different perspectives on suggested changes. Two key suggestions that I am offering refer to:

- 1) adding “energy ratios” to the ARB document, and
- 2) avoiding the use of ARB “default” values as a basis for your calculations, but instead use recognized industry standard references as a basis for your estimates and calculations.

These two suggestions are described in more detail in the attached document. (SPT1)

Response: In response to the first suggestion, the ARB analysis measures GHG emissions on a carbon intensity basis and presents these as gCO₂e/MJ. Producers may elect to use ‘energy ratios’ or other metrics for their comparisons but to participate in the LCFS, they must use the carbon intensity metric used by ARB.

In response to the second suggestion, the values used to generate the carbon intensities for various fuels in the adopted Lookup Tables have either used industry average values or have used values specific to a pathway based on technology (e.g.

high efficiency liquefaction) or other specific criteria. All producers that participate in the LCFS must provide verifiable information to use the pathway designated value. If their pathway is different from the adopted pathway, they can create one using Method2A/2B following a rulemaking.

IV-142. Comment: Page 37, §95485(a)(1) Table 4. The energy content of “Neat Biomass-based diesel (gal)” varies. I suggest you publish representative energy contents for renewable diesel and biodiesel with a footnote that energy contents may vary depending upon process and feedstock selection. (A204NESTE3)

Response: We do use one value for biodiesel and another for renewable diesel. We understand that there could be variability in the heating values from different producers but it would be almost impossible to guarantee that every batch from the same producer has exactly the same value and would also be difficult to enforce. The analysis has considered averages and these have been presented in the pathway documents. This is the same approach used for CARBOB and diesel. This is to help ensure the fungibility of the fuel distribution system.

D. Regulatory

APA Issues

IV-143. Comment: The modified regulatory text, by placing the ARB Lookup Table in section 95486, raises new questions under the APA concerning Method 2, which are also relevant to the Concept Paper published on August 4. First, there are substantial problems of clarity with respect to Method 2. “Customized” carbon intensity values must reflect any indirect effects, which according to the proposed regulatory text will entail “use [of] the GTAP model, which is incorporated by reference, or other model determined by the Executive Officer to be at least equivalent to the GTAP model.” See 17 C.C.R. § 95486(c)(3) (proposed), (d)(5) (proposed). This raises a host of issues. There is no fixed version of “the GTAP model,” and a party interested in the requirements of Method 2 therefore cannot know from the regulatory text (nor from the Concept Paper) which set of GTAP algorithms are being adopted. Growth Energy understands, for example, that there is already a new version of GTAP – called GTAP7 – under development to include indirect land-use predictive capabilities. The vague reference to GTAP therefore fails the clarity standard for California regulations. It is also not clear how the Executive Officer would determine “equivalence” – which is also a problem of lack of clarity in itself. The incorporation by reference provision in the proposed regulatory text also does not meet the requirements of the APA, because there is no specificity in the description of which version or versions of GTAP and its input/output tables are being incorporated. Each of these deficiencies alone would fail the clarity standard; combined in a single subpart of a single section of the LCFS regulation, they leave interested members of the public with no notion of how to make a satisfactory Method 2 demonstration. (GE4) LEGAL

Response: The final versions of sections 95486(c)(3) and (d)(5) of the regulation have been modified to incorporate a specific February 2009 version of the GTAP model, the components of which are identified in section 95481(a)(20.5). This addresses the clarity concerns raised by the commenter.

IV-144. Comment: In addition to being substantively invalid, the proposed addition of the new cane ethanol pathways to the regulation would violate the APA in two important respects. First, the new cane ethanol pathways are not “sufficiently related” to the text considered and approved by the Board at the April 2009 hearing to permit them to be added now under the post-hearing amendment provisions in section 11346.8 of the Government Code. Prior to these additions to the ARB Lookup Table, the “reasonable member of the directly affected public” posited by 1 C.C.R. § 42 would have supposed that the addition of new pathways was to be accomplished in the manner described in the ISOR and the original staff publications, through the use of the “Method 2” procedures. The ISOR contained **one** cane ethanol pathway. See, e.g., ISOR at ES-20. The document containing the staff’s proposed changes to the regulatory text disseminated at the

time of the April hearing contained **two** cane ethanol pathways. It was not until the publication of the 30-day notice that a **third** cane ethanol pathway appeared, with a direct carbon intensity value less than one-half the only direct carbon intensity value in the ISOR, and based upon what now appears to be the flawed analysis of GHG emissions based upon use of “mechanized harvesting.” The public might have anticipated **two** cane ethanol pathways because of the Board’s action, but certainly not the creation of a **third** cane pathway. The notice requirements of the APA are essential to the fairness of the California public hearing process. OAL enforces the limits on late amendments to proposed regulations. OAL will disapprove agency actions that are not based on adequate notice to the public, as required by Gov. Code § 11346.8(c), when it finds that a final regulation was not sufficiently related to the original text.” (GE4)

Response: Government Code section 11346.8(c) governs the degree to which an agency is authorized to adopt final regulations that differ from the original proposal without issuing a new 45-day notice. It authorizes a state agency to adopt a regulation, which has been changed from that from that made available with the hearing notice, as long as the changes are “sufficiently related to the original text that the public was adequately put on notice that the change could result from the originally proposed regulatory action.” An OAL regulation – section 42, title 1, CCR – further interprets this requirement by providing that,

Changes to the original text of a regulation shall be deemed “sufficiently related,” as that term is used in Government Code Section 11346.8, if a reasonable member of the directly affected public could have determined from the notice that these changes to the regulation could have resulted.

A core principle of administrative procedure is that the reason for conducting a public hearing is to enable the decision-maker to consider and, where appropriate, adopt changes to the originally noticed proposal. In the leading California case in this area, the court explained:

[E]ventual adoption of a regulation differing from that described in the pre-hearing notice is an objective of the hearing process. Fairness too is a statutory desideratum. After an opportunity for participation in a hearing considering the subject or issue evoked by the pre-hearing draft or summary, affected interests cannot claim unfairness when the agency’s consideration of new information and views persuades it into a different enactment dealing with the identical subject or issue. To confine the agency to the terms of its pre-hearing proposal would negate the basic purpose of the hearing. To require a new notice and hearing would tie the agency into time-consuming, circular proceedings transcending the statutory objective.

Schenley Affiliated Brands Corp. v. Kirby, 21 Cal.App.3d 177, 193 (1971), cited approvingly in *Western Oil and Gas Ass'n v. Air Resources Board*, 37 Cal.3d 502, 526 (1984).

The commenter focuses not on whether the third cane ethanol pathway was “sufficiently related” to the originally proposed regulatory text, but rather on whether it was sufficiently related to the modified provisions – including specifying two cane ethanol pathways that were to be part of the Lookup Table in the regulation – that the Board approved at the conclusion of the April 2009 hearing. There is no APA provision limiting departures from interim agency determinations made in the middle of the rulemaking process. Once the Board decided to place the Lookup Table carbon intensity values in the regulation itself, and to provide that additional values could only be added as part of a rulemaking proceeding, it would come as no surprise that ARB would use this initial rulemaking to identify carbon intensity values for any additional pathways for which sufficient supporting data could be developed and made available for supplemental public comment. The supplemental comment period during which the public had the opportunity to comment on ARB’s modifications to the original proposal was triggered not by Resolution 09-31 but by the 30-day notice of availability issued July 20, 2009, and that notice covered all three cane ethanol pathways.

Identification of the three cane ethanol pathways in the final regulation was also sufficiently related to the original proposal and all three pathways could accordingly be included in the final regulation consistent with Government Code section 11346.8(c). As explained in Section II.B.1. of this FSOR, under the original proposal the regulation itself would not identify any fuel pathway carbon intensity values. Instead, upon adoption of the regulation, the Executive Officer would be directed to certify Method 1 carbon intensity values for various fuels and fuel pathways; these carbon intensity values would then be published in a Lookup Table to be used by regulated parties. It was expected that these would include the fuel and fuel pathway carbon intensity values identified by staff in the Staff Report with modifications reflecting any updated information and any new fuel pathways. The Executive Officer could subsequently certify new carbon intensity values or modifications to the Lookup Table values at his or her own initiative without initiating a new rulemaking. This mechanism was separate from Methods 2A and 2B, which provided a means by which a regulated party could apply for Executive Officer certification of a modified or new pathway.

The commenter makes no suggestion that the Board’s decision to make the Lookup Table carbon intensity values part of the regulation in place of the certification process was not “sufficiently related” to the original proposal. After all, this significant modification was made in response to public comment. Further, the commenter implicitly acknowledges that the public might have anticipated two cane ethanol pathways in the final regulation, even though only one cane ethanol pathway was included in Table IV-20 of the Staff Report. If a Lookup Table in the regulation with two cane ethanol pathways was sufficiently related to the original proposal, there is no reason why a Lookup Table with three cane ethanol pathways would be viewed differently. Indeed, Attachment B to Resolution 09-31 put the public firmly on notice that

there could be multiple pathways for cane ethanol added to the modified regulatory text (“As part of the 15-day change process, the final regulation will specify carbon intensity values for one **or more pathways** for each of the additionally identified fuels [including sugarcane ethanol]) (emphasis added). Attach. B to Reso. 09-31 at 7.

IV-145. Comment: The second APA violation, which would exist even if the new cane ethanol pathways were otherwise “sufficiently related” to the original regulatory text, arises from the failure to revise critical parts of the regulatory support documents to account for the new cane ethanol pathways. If the Executive Officer intended to include the new carbon intensity values in the final regulation, he should at a minimum have prepared and published a revised version of Appendix E of the ISOR (his compliance analysis of the LCFS regulation), and permitted public comment on the new compliance analysis. In addition, he should have considered whether the new cane ethanol pathways warranted a different declaration concerning competitive impacts under section 11346.5 for California businesses. See, e.g., Cal. Gov’t Code § 11346.5 (a)(7), (8). Putting aside the other reasons why the predicted use of California-produced ethanol in the ISOR is unrealistic, it is implausible that the introduction of a new ethanol pathway with a carbon intensity value nearly 20 gCO₂e/MJ below the lowest California pathway would not warrant some change in one or more of the Executive Officer’s compliance scenarios. At this point, it is unclear whether the Executive Officer still believes, or could credibly claim, that California “Low Carbon Intensity Corn Ethanol” will still account for 300,000 million gallons of ethanol produced annually for California through 2020, as predicted in Appendix E, in each of the scenarios in Appendix E. In other situations, when developments after the publication of a 45-day notice have warranted changes in material portions of an ISOR, the Executive Officer has revised the relevant tables and published them for public comment. (GE4)

Response: We did include sugar cane ethanol in several of our compliance scenarios. With a lower carbon intensity, it would certainly be plausible to show additional compliance scenarios with higher volumes of sugar cane ethanol. We already have four scenarios and one supplemental scenario for compliance with the gasoline standard. The addition of another sugar cane ethanol scenario is not needed to demonstrate the feasibility of the LCFS gasoline standard. As for the 300 million gallons per year of California corn ethanol production, because that production capacity already exists, and with lower lifecycle GHG emissions associated with the newer California facilities, and with the potential co-product credit for wet DGS, it is plausible that those facilities could remain competitive through 2020.

Regulatory Language

IV-146. Comment: If ARB based their numbers for “North American natural gas, liquefied in California and used in California” using Clean Energy’s LNG plant in Boron, California, there would be no question that the “North American natural gas, liquefied in California and used in California” pathway would receive the

same "opt-in provision" allocated to electricity, hydrogen, hydrogen blends, fossil CNG derived from North American sources, biogas CNG, and biogas LNG under §95480.1 (b).

ARB must include the "North American natural gas, liquefied in California and used in California" pathway under the list of "opt-in" fuels based on its own conservative data and the knowledge that the actual LNG fuel being processed in California and delivered to California fleets far surpasses the carbon content threshold to qualify for such exemption. To not do so would mischaracterize and potentially harm California's existing LNG production industry dedicated to vehicle transportation, send a damaging message to our clients and potential markets, and would ultimately undermine the very goals that the LCFS is attempting to achieve. (CE5)

Response: The fuels "opt-in" provision is section 95480.1(b). Since there are no modifications proposed for this section, this comment falls outside the scope of the First 15-Day Change Notice and requires no further response.

IV-147. Comment: Pages 1, 2, 4 & 5, § 95480.1.(a)(11): The use of the term ("B100") in § 95480.1.(a)(11) Neat biomass-based diesel ("B100"); conflicts with the definitions in §95481.(a)(2) "B100" means biodiesel meeting ASTM D6751-08... and §95481.(a)(9) "Biomass-based diesel" means a biodiesel (mono-alkyl ester) or a renewable diesel that complies with ASTM D975-08ae1.... The term ("B100") should be deleted from §95480.1.(a)(11). There are more references to B100 in the text that tie B100 to biodiesel. Deleting ("B100") from §95480.1.(a)(11) does not interfere with those uses and is the best solution to this conflict. (A204NESTE3)

Response: This comment falls outside the scope of the First 15-Day Change Notice. The only change that was proposed with respect to the "neat biodiesel" and "biomass-based diesel" definitions was the identification of the publication or edited dates for the applicable ASTM test methods (D6751-08 and D975-08ae1, respectively). Because the commenter is not addressing either the appropriateness of these dates or staff's process in proposing these dates, the comment falls outside the scope of the First 15-Day Change Notice. Therefore, no further response is required.

IV-148. Comment: Page 5 §95481.(a)(15): The lack of mention of renewable diesel in: §95481.(a)(15) "Diesel Fuel Blend" means a blend of diesel fuel and biodiesel containing no more than 5 percent (B5) biodiesel by weight and meeting ASTM D975-08ae1, (edited December 2008), Specification for Diesel Fuel Oils, which is incorporated herein by reference. (A204NESTE3)

Response: This comment falls outside the scope of the First 15-Day Change Notice. The only changes that were proposed with respect to the definition for "diesel fuel blend" was the identification of the test method's edited date and formal title, "(edited December 2008), Specification for Diesel Fuel Oils," and its incorporation by reference.

Because the commenter is not addressing the appropriateness of the date, the method's title, or the regulation's incorporation of the method by reference, the comment falls outside the scope of the First 15-Day Change Notice. Therefore, no further response is required.

IV-149. Comment: It may lead to confusion unless the regulations indicate that the diesel fuel may contain renewable diesel. Because renewable diesel is diesel fuel as defined in: 13 CCR §2281(b) "Diesel fuel" means any fuel that is commonly or commercially known, sold or represented as diesel fuel, including any mixture of primarily liquid hydrocarbons – organic compounds consisting exclusively of the elements carbon and hydrogen – that is sold or represented as suitable for use in an internal combustion, compression-ignition engine. I recommend the following clarifying language: §95481.(a)(15) "Diesel Fuel Blend" means a blend of diesel fuel (including renewable diesel) and biodiesel containing no more than 5 percent (B5) biodiesel by weight and meeting ASTM D975-08ae1, (edited December 2008), Specification for Diesel Fuel Oils, which is incorporated herein by reference. (A204NESTE3)

Response: This comment is outside the scope of the First 15-Day Change Notice because no modifications are proposed for the definitions of "diesel fuel" in section 95481(a)(14) or "renewable diesel" in section 95481(a)(40) (other than a grammatical change). Therefore, no further response is required.

IV-150. Comment: We recommend the terms "Biodiesel" and "Renewable diesel" as defined in Section 95481(a)(3)(E) and Section 95481(a)(40)(D), respectively, be revised to read, "Derived from nonpetroleum renewable resources, including, but not limited to, municipal wastewater treatment solids." (LACSD)

Response: This comment falls outside the scope of the First 15-Day Change Notice. The only change that was proposed with respect to the definition for "biodiesel" was the identification of the publication date for the applicable test method. For "renewable diesel," the only change proposed was a nonsubstantive grammatical correction. Because the commenter is not addressing either of these changes, the comment falls outside the scope of the First 15-Day Change Notice. Therefore, no further response is required.

IV-151. Comment: We recommend removing the requirement to meet 13 CCR Section 2292.5 for the term "biogas" as defined in Section 95481(a)(5), and including this requirement for the term "biogas CNG" as defined in Section 95481(a)(6). (LACSD)

Response: This comment falls outside the scope of the First 15-Day Change Notice. The language requiring that biogas meets the requirements in 13 CCR sec. 2292.5 was not changed from the initially proposed regulatory language and therefore was not subject to public comment under the First 15-Day Change Notice. Because the comment falls outside the scope of the notice, no further response is required.

IV-152. Comment: Clean Energy is curious as to why the definitions for Oil Sands and Oil Shale were deleted from the LCFS regulatory language as these fuel sources are likely to be used in the future marketplace. (CE5)

Response: As explained in the First 15-Day Change Notice, the definitions for “oil sands” and “oil shale” (formerly section 95481(a)(34) and (35)) were deleted because those terms were not used elsewhere in the regulation approved for adoption under Resolution 09-31.

Reporting Requirements (§95484)

IV-153. Comment: At a minimum WSPA recommends the following language to be added to 95484d(2)(B): "...submitted by any regulated or nonregulated party..." We note that regulated parties may use pathways of other regulated parties if they are identical. (WSPA4)

Response: We agree and have modified the regulatory text accordingly, as noted in the Second 15-Day Change Notice.

IV-154. Comment: For the purpose of demonstration of physical pathway, we recommend that the Importer be defined as the product titleholder when the fuel/blend stock enters California, this may be a producer, buyer, or marketer. (WSPA4)

Response: The term "importer" was not modified in the First 15-Day Change Notice with respect to the demonstration of physical pathways or in any other provision. Therefore, this comment falls outside the scope of the First 15-Day Change Notice and requires no further response.

IV-155. Comment: The addition of deadlines to 95484d(2)(F) is appropriate in concept, but the deadlines are much too short. (WSPA4)

Response: We agree and, in the Second 15-Day Change Notice, have modified the language to require a regulated party to notify the Executive Officer within 30 working days of a material change in an approved physical pathway. We also eliminated the requirement to notify the Executive Officer of non-material changes to an approved physical pathway. We believe 30 working days (approximately 40 calendar days) provides ample time for the written notification requirement to be met.

IV-156. Comment: In relation to 95484d(2)(G)(5), WSPA requests further information on ARB's commitment to provide a universal access website to all involved parties and to keep it up to date. The rule refers only to names and contact numbers. It would be ideal if the pathway approvals could be directly posted on line for use by all parties where a fuller description of the pathways is included. (WSPA4)

Response: We agree and have modified the regulatory text to require the Executive Officer to publish on the ARB website details of each approved physical pathway in accordance with the requirements of 17 CCR §§ 91000 – 91022 and the California Public Records Act (Government Code section 6250 et seq.). This change is described in the Second 15-Day Change Notice.

IV-157. Comment: References in the body of the physical pathway section need to be updated to reflect changes in reference numbering of this section made by ARB. (WSPA4)

Response: We agree and have corrected the internal numbering references accordingly.

IV-158. Comment: ARB should encourage the demonstration of physical pathways by producers, importers, and marketers as soon as practical given the importance of physical pathway to generation of LCFS credits. We are concerned that the level of detail requested in the demonstration of physical pathway language is excessive, impractical, and could discourage parties from registering physical pathways. In order to provide guidance to the industry, WSPA recommends that ARB publish an example of physical pathway demonstration that would be acceptable to the Executive Officer. (WSPA4)

Response: We agree that there is merit in publishing such examples and will work with interested stakeholders to accomplish this goal.

IV-159. Comment: Clean Energy opposes any requirement under the LCFS's regulatory language that requires a regulated party to pay for the actual physical transfer of molecules through an agreed upon physical pathway if a commodity swap can be established and documented between two parties. Such swaps are common practice within the Industry, accepted by the Federal Energy Regulatory Commission, and should be accepted under the final regulatory language of the LCFS. ARB staff has argued that allowing physical swaps as Clean Energy suggests might open up the option to perform swaps to other Industries such as ethanol or biodiesel. Clean Energy respectfully disagrees. Unlike ethanol and biodiesel, biomethane that is pipeline quality has an established pathway via use of the existing pipelines. Neither ethanol nor biodiesel to date have national pipelines that can deliver fuel to California customers. Railways are also very different from pipelines. Natural gas pipelines carry natural gas. They do not carry other product. Railways carry all sorts of product, not just ethanol or biodiesel. In other words, even if Clean Energy did not pay for the physical transfer of a biomethane molecule from Dallas to California, it is still possible that the biomethane molecule could reach California. Not so with railways as freight requires a destination. We therefore ask that ARB modify the regulatory language to allow for physical swaps within natural gas pipeline systems as the failure to do so would only harm the Industry and hurt ARB's LCFS goals for 2020 and beyond. (CE5)

Response: Essentially, the commenter is suggesting that the LCFS should not strictly require a regulated party for natural gas to demonstrate a physical pathway by which the gas would reach California. Rather, the regulation should allow a regulated party to pay, for example, a biogas producer in Iowa to put biogas into the Iowan pipeline, with full knowledge that there is little to no chance that the biogas would actually make it to California (i.e., a "virtual" swap).

This suggestion conflicts with a basic premise of the LCFS regulation, which is to encourage the reduction of GHG emissions associated with transportation fuel used in California. If regulated parties are allowed to conduct the “virtual” swap of pipeline gas in the suggested manner, this basic goal would be undermined. Accordingly, it was determined that the issue raised did not warrant modifications to the language in section 95484(d)(2)(D) and (E) (formerly (B) and (C)). Because no changes were made to the originally proposed language, this comment falls outside the scope of the First 15-Day Change Notice. Therefore, no further response is required.

IV-160. Comment: While we understand the rationale for the suggested changes to section 95484(d)(2) (“evidence of physical pathway”) and believe the modifications could indeed streamline the demonstration process, we are somewhat concerned about the notion of this regulatory burden being pushed down to fuel producers that are not regulated parties. Certainly, the non-regulated producers and marketers of the low carbon fuels that will be used by regulated parties to comply with the LCFS will play an important role in providing evidence of the physical pathway. However, the pathway demonstration is ultimately the responsibility of the regulated party and we are concerned that this modification may enable regulated parties to effectively circumvent this responsibility simply by requiring non-regulated fuel producers to produce the pathway demonstration. We encourage ARB to ensure that this modification does not have the undue consequence of indirectly attempting to regulate parties that do not fall within the definition of “regulated parties.” (RFA3)

Response: The commenter’s concerns are misplaced. The modifications to section 95484(d)(2) allow, but do not require, a non-regulated party fuel provider to obtain approval for a physical pathway. This is intended to allow cost savings for regulated parties who can cite such approved physical pathways as part of their own pathway demonstrations. Nonetheless, the obligation to comply with the demonstration of physical pathways still falls on regulated parties rather than non-regulated parties.

IV-161. Comment: There should be a revision in section (c)(3)(C)1 in the metering language. We believe it should say:

1. For charging stations, the total electricity dispensed (in kWh) to all vehicles based on direct metering, which distinguishes electricity delivered for transportation use. Before January 1, 2015, “based on direct metering” means either:

a. the use of direct metering (also called sub-metering) to measure the electricity directly dispensed to all vehicles at each charging station; or

b. Where direct metering has not been installed, the regulated party may report the total electricity dispensed at each charging station using another method that the regulated party demonstrates to the Executive Officer’s satisfaction is substantially similar to the use of direct metering under section (c)(3)(C)1.a.b. Where direct metering has not been installed, the

regulated party may report the total electricity dispensed at each charging station using another method that the regulated party demonstrates to the Executive Officer's satisfaction is substantially similar to the use of direct metering under section (c)(3)(C)1.a. (COULOMB)

Comment: CalETC supports the draft language, which gives the ARB Executive Officer authority to approve alternatives to direct metering for residential charging stations before January 1, 2015. However, we believe that this authority should not be limited to residential charging stations, but should be extended to all charging applications, including commercial, industrial, and public charging, if the regulated party can demonstrate to the Executive Officer's satisfaction that the alternative method is substantially similar to the use of direct metering. Accordingly, we ask that the restriction in the draft language limiting the authority of the Executive Officer to approve alternatives to direct metering of residential charging only be removed. (CAETC3)

Response: The commenter's request that commercial applications be allowed to use an alternative to direct metering through 2015, as is currently allowed for residential home charging of electric vehicles where submetering is not yet available. While ARB recognizes the need for additional time for the rollout of residential submetering for electrical vehicle charging, we believe it is appropriate to require direct metering for electric vehicle charging in non-residential applications.

IV-162. Comment: Pursuant to Resolution 09-31, staff modified the reporting requirements for residential charging stations to permit alternative reporting methods that are shown to the Executive Officer to be substantially similar to direct metering (also called "submetering"). WSPA believes direct metering should be the requirement to encourage installation of the infrastructure, and then a protocol should be provided for an alternative methodology that can be demonstrated to be equivalent.

We suggest the following addition to this section:

(b). "for households and residences...the regulated party demonstrates through section 95490 Enforcement Protocol to the Executive Officer's satisfaction..." (WSPA4)

Response: The provision allowing an alternative to direct metering for residential applications is intended to give additional time for the standardization and rollout of submetering technology in residences. Because the amount of current residential ZEV charging is limited, work is underway to implement the submetering technology, and the provision sunsets in 2015, the risk of over-crediting is minimal. ARB will continue working with utilities and other interested stakeholders to evaluate alternatives to direct metering for estimating electric vehicle charging in residential applications when submetering is not available.

IV-163. Comment: The solution to global warming is to provide tax credits to the oil companies to install CNG/LNG pumps for public use at their gasoline stations. (FISHER1, FISHER3)

Response: Awarding tax credits is outside the scope of the agency's jurisdiction.

IV-164. Comment: Clean Energy is disappointed that ARB appears to have ignored prior comments submitted by not including a subsection (C) under - §95484. (b)(3). *Deficit Carryover* that requires any regulated party with a negative credit balance to purchase available credits generated and up for sale on the LCFS trading floor before that regulated party can carryover its deficit to the next year. Public statements have been made by many regulated parties that currently dominate California's Transportation Fuel Industry that they would resist purchasing any credits from their competition: California's emerging Low Carbon Fuel Industry. Clean Energy and other regulated parties who can offer low to ultra low carbon fuel solutions have asked ARB to make this requirement within the LCFS regulatory language. Failure to do so may make accounting for LCFS credits less attractive for companies like Clean Energy who's fuels are within the "opt-in" category because ARB has simply provided the dominant players in California's transportation fuel market too much flexibility. Such an outcome could be disastrous as it could threaten the LCFS market and the very goals of the LCFS goals if most companies decide not to account for credits generated. Again, we urge ARB staff to add a subsection (C) that would disallow the carryover of negative credit balances if LCFS credits are available for sale on the LCFS market. (CE5)

Response: There are no changes to Section 95484(b)(3). Therefore, this comment falls outside the scope of the First 15-Day Change Notice and requires no further response. Also, see Comments D-3 and D-4.

IV-165. Comment: We support the modified language in Section 95484(d)(2) that allows fuel producers who do not fall within the definition of "regulated party" to demonstrate or provide sufficiently-detailed demonstrations of the delivery methods comprising the physical pathway. This will help lessen the burden for a regulated party when trying to obtain approval for a pathway that has not been developed and adopted in the LCFS regulation. (LACSD)

Response: No response is required.

Credits and Deficits (§95485)

IV-166. Comment: In our April 17 letter we expressed concern that 95485(c)(1)(B) and (C) seemed to be contradictory. The proposed modification acknowledges this contradiction and addresses it by adding the phrase "except as otherwise specified in (C) below." Unfortunately, by adding two commas and changing

“that” to “which” in (B), the amendments change the meaning in a way we do not believe staff intends.

We believe (B) is intended to say that a subset of third parties, specifically those that are not a regulated party or acting on behalf of one, are prohibited from acquiring or transferring LCFS credits unless doing so in compliance with (C). If so, (B) should read:

“(B) acquire or transfer LCFS credits. A third-party entity that is not a regulated party or acting on behalf of a regulated party may not purchase, sell, or trade LCFS credits, except as otherwise specified in (C) below; and”. (CNGVC3)

Response: We disagree. It is unclear the suggested change would make the provision clearer. Indeed, by removing the commas, the commenter’s changes would make the language grammatically incorrect. We believe the language as modified in the First 15-Day Change Notice reflects the commenter’s intent while being grammatically correct.

IV-167. Comment: Use of the revised language in 95485(c)(1)(B) seems to allow a third party, not related to the program, but perhaps regulated parties under other GHG initiatives, to purchase credits and retire them outside the LCFS credit pool. This would reduce the credit pool available for purchase and compliance use by our industry and inappropriately inflate the value of credits. This is of possible concern.

WSPA does agree, given the uncertainty of the size of the LCFS credit market that ARB should make every effort to ensure regulated parties have access to the LCFS credits they may need for compliance. Allowing non-regulated parties or other entities the ability to acquire/trade LCFS credits could hinder the ability of obligated parties to comply with the law, and potentially distort the market for credits by artificially inflating the value of LCFS credits. (WSPA4)

Response: This comment falls outside the scope of the First 15-Day Change Notice. The modification to the regulatory text at issue was made only to address the apparent conflict and confusion between section 95485(c)(1)(B) and (C). As noted in Attachment B to Resolution 09-31, section 95485(c)(1)(B) and (C) as originally proposed created confusion in that (c)(1)(C) appeared to allow the export of LCFS credits to other GHG initiatives. But (c)(1)(B) as originally proposed appeared to prohibit at least some of the sales to such initiatives because it prohibited those entities, which are not LCFS regulated parties or acting on behalf of such regulated parties, from buying LCFS credits for use in an AB 32-type program. This was not consistent with the intent of the originally proposed language, which was to allow the export of LCFS credits to AB 32-type GHG reduction programs, regardless of whether the export was to a regulated party or a non-regulated party. Thus, the confusion between the two provisions necessitated the modification described in the First 15-Day Change Notice.

As noted, the modification in the First 15-Day Change Notice was to clarify, but not change, the original language's intent to allow exports to AB 32-type programs. However, the commenter seems to have an issue with the principle itself of exporting credits out of the LCFS program for use in an AB 32-type program. Because that principle was not modified in the modified regulation order, the comment falls outside the scope of the First 15-Day Change Notice. Therefore, no further response is required.

Determination of Carbon Intensity (§95486)

IV-168. Comment: The Sanitation Districts oppose the proposal in the Modification Regulation Order to adopt the look-up tables and the carbon intensity values (Table 6 and Table 7) in Section 95486(b)(1):

a. Table 6 and Table 7 include only limited fuel pathways and carbon intensity values developed between the initial published proposed concept outline for the LCFS in March 2008 and the current Modified Regulation Order, available for public review on July 20, 2009. These two tables will evolve drastically once regulated parties are given the opportunity to submit for approval alternative fuel pathways for low carbon fuels that have not yet been considered. It is inefficient to adopt the two tables and the carbon intensity values into the regulation knowing it will be amended and expanded soon after the adoption of the Modified Regulated Order (and continually thereafter). The traditional regulatory amendment process is both extensive and time consuming. This could stagnate the alternative low carbon fuels industry that relies on the incentives in regulations such as the LCFS regulation to help enter the transportation fuel market. Slowing down the industry that is trying to infuse low carbon fuel into the market goes against the goal of the LCFS to accelerate the reduction of carbon intensity of California's transportation fuel supply by ten percent come 2020.

b. Table 6 and Table 7 do not include fuel pathways and carbon intensity values for low carbon fuels that are alternative substitutes for gasoline or diesel, such as fuels derived from renewable biomass, such as CNG/LNG/hydrogen/electricity from wastewater digester gas, or any pathways for fuels from green waste, bio-solids, and crops from marginal lands. The Sanitation Districts previously recommended that waste-derived alternative fuels should be explicitly recognized and incentivized in the LCFS. Adoption of these two tables without the inclusion of fuel pathways from waste-derived fuels will only make it more difficult for this important segment of the potential low carbon producing industry to enter the market. (LACSD)

Response: With respect to the comment in a., we disagree. The need for changes to the Lookup Tables to undergo a formal rulemaking is explained in Section II.B.2.

With respect to comment b., we agree and accordingly have incorporated additional pathways in the Carbon Intensity Lookup Tables (Tables 6 and 7 in section 95486). These include pathways for waste-derived fuels such as landfill biogas (bio-methane) to biogas CNG and LNG, as well as dairy digester biogas to CNG and LNG. Additional pathways for electricity and hydrogen derived from renewable sources were also added. While a pathway for cellulosic ethanol has not been added, staff is continuing to monitor advancements in this field. When the LCFS regulation goes into effect, regulated parties that provide cellulosic ethanol and other waste-derived fuels will have the opportunity to submit their fuel pathways for inclusion into the Lookup Tables under the rulemaking process set forth in Methods 2A or 2B (section 95486).

IV-169. Comment: ARB released their preliminary draft for public comment on Method 2 in which a regulated party has the opportunity to present a new pathway or a sub-pathway of an already approved pathway. We again applaud this opportunity, but take serious concern to the possibility of a fee schedule being attached to Method 2 submissions. The reason for this concern is that we don't believe you have taken into account all types of ethanol production practices. For instance, here in Nebraska, some of the plants produce a modified wet distillers grains (MWDG). This product has a dry matter in the range of 45-50 percent. Currently you do not have a pathway for the production of MWDG and in order to quantify this pathway that you do not have, a regulated party will need to pay a fee for an approved pathway. This again, raises serious concerns, as it seems a pay to play mentality. (NCB2)

Response: This comments falls outside the scope of the First 15-Day Change Notice because the modified regulation order does not contain any provisions for a fee schedule. Accordingly, no further response is required.

IV-170. Comment: ARB has removed, in Section 95486(f)5, the requirement for the EO to approve or disapprove a new pathway within 45 days after the public review process and instead approve or disapprove an application in accordance with the applicable provisions of the Administrative Procedure Act (APA). If the APA does not define a time schedule for approval or disapproval of a new pathway, or if it exceeds 90 days, we request the Agency define a time for approval within 45 to 90 days; it should not be left open-ended. (WSPA4)

Response: We disagree. By directly referencing the APA requirements, the modified regulatory language now provides for review periods that are specifically defined under State law, rather than open ended. This is because the Carbon Intensity Lookup Tables were added to the regulatory text in the First 15-Day Change Notice. Therefore, changes to the Lookup Tables to include new or modified pathways pursuant to Methods 2A or 2B (section 95486) will necessitate a formal rulemaking. Under the APA, a rulemaking to amend the LCFS is required to undergo a minimum public review of 45 days before it can be adopted (generally by the Executive Officer using authority delegated to him/her by the Board in Resolution 09-31).

Requirements for Multimedia Evaluations §95487

IV-171. Comment: WSPA supports the added language specifying the substantive Executive Officer reviews of the LCFS implementation, but believes such reviews should be conducted at regular periodic intervals, perhaps every three years rather than just 2012 and 2015. WSPA also requests that EER's be placed on the regulatory review list as an item that must be reviewed for possible revision during the periodic reviews. (WSPA4)

Response: The regulation as approved by the Board with modifications provides for adequate Executive Officer reviews. Under the modified language in section 95489, the Executive Officer is required to conduct a minimum of two formal reviews, the first by January 1, 2012 and the second by January 1, 2015. Further, in Resolution 09-31 the Board directed the Executive Officer to monitor the implementation of the LCFS program and propose amendments to the regulation when warranted. Given the two formal reviews and the Board's directive for the Executive Officer to monitor the program's implementation, the Board believes it is unnecessary to incorporate more periodic reviews into the regulation beyond that which is currently specified.

IV-172. Comment: Pursuant to Resolution 09-31, staff added a provision that permits the Executive Officer to enter into enforceable written protocols with regulated parties under specified conditions (new section 95490). WSPA supports these changes, and asks that such protocols also be allowed under section 95486; at least until more details are specified on HCICO calculations and the methodology for dealing with out-of-state GHG reduction programs are defined. (WSPA4)

Response: As noted previously, the requirements for treating HCICO were revamped comprehensively based on extensive input from WSPA, member companies and other stakeholders. The modified regulatory text was released in the Second 15-Day Change Notice, which we believe contains sufficient specificity as to make the use of enforcement protocols unnecessary. Further, it is somewhat premature to speculate on the need for enforcement protocols to deal with out-of-state GHG reduction programs given the dearth of such programs at the present. Nonetheless, the need for using enforcement protocols for other aspects of the LCFS can be considered by the Executive Officer in the formal program reviews (i.e., the list of topics within the scope of the Executive Officer's review under section 95489 represents a minimum, rather than an all-inclusive list).

IV-173. Comment: The LCFS requires regulated parties to submit information to ARB, which includes fuel volume, carbon intensity values for each blend stock, credits, and deficits generated under the program. In addition, regulated parties are required to submit evidence of physical pathways used for each transportation fuel and blend stocks regulated by ARB. Where a regulated party has developed a "new fuel pathway," they are also required to submit data, calculations and other documentation supporting the proposed pathway, and how carbon intensity values were derived. Our position is that this type of information is confidential

business information, and should be protected as “trade secret” under the LCFS regulation.

ARB should reconsider the proposed LCFS regulation’s treatment of confidential business information, as the proposed method is inconsistent with both the Public Records Act and ARB’s own regulations relating to the disclosure of confidential information. (WSPA4)

Response: For information submitted pursuant to the physical-pathway demonstration requirements under section 95484(d)(2), language was added in the Second 15-Day Change Notice to clarify that the details of approved physical pathways would be publicly available in accordance with the requirements of sections 91000-91022, title 17, CCR and the California Public Records Act (Government Code section 6250 et seq.). Further, the originally proposed regulatory text already provided for regulated parties to identify specific information as trade secrets for purposes of submitting a proposed fuel pathway for approval under Method 2A or 2B in section 95486. The originally proposed language already provided for such information to be treated in accordance with the requirements of sections 91000-91022, title 17, CCR and the California Public Records Act (Government Code section 6250 et seq.). For all other information submitted to ARB, no changes were made to the originally proposed regulatory text with regard to the identification and treatment of trade secrets. Therefore, the comment as it pertains to such information falls outside the scope of the First 15-Day Change Notice and requires no further response.

IV-174. Comment: ARB should require producers supplying biofuels to California or the entities that bring the biofuels into the state to register their production facilities. Registration should include the carbon intensity(ies) of the biofuel(s) produced at the production facility from the Look-Up Table. A listing of registered producers and their production facilities should be maintained on the ARB website and could be associated with the ARB carbon intensity look-up table. (WSPA4)

Response: To the extent biofuel producers supply transportation fuel or blendstock to California, they were already required under the originally proposed text to demonstrate their fuels’ physical pathways if they wanted to receive credit for such fuels under the LCFS program. Similarly, under the originally proposed regulatory text the biofuel providers would already be “required” to supply carbon intensity information, either directly to ARB as regulated parties or indirectly via the producer or importer to which they supply their biofuels.

To the extent that such biofuel producers do not supply fuel directly to California and have no other contacts with California, there likely would be jurisdictional issues with requiring them to register their facilities and carbon intensities. Thus, to encourage the submittal of LCFS-related information from such facilities, we modified the regulatory text in the Second 15-Day Change Notice to allow biofuel producers, which do not otherwise qualify as regulated parties, to demonstrate a physical pathway to California.

The intent of this modification is to provide the fuel producers who purchase such biofuels and bring them into California a way by which they can cite to and rely on those approved physical pathway demonstrations submitted by non-regulated party biofuel producers.

Treatment of High Carbon Intensity Crude

IV-175. Comment: The issue of treatment of high carbon intensity crude oil (HCICO) is an important one, and ARB needs to finalize the regulatory language on the treatment of HCICO. During the original 45-day comment period, WSPA expressed our concern that the original HCICO proposal would not maintain product fungibility and would be operationally unworkable. Unfortunately, the revisions included in this 30-day package address neither of our concerns.

In addition to the fundamental issues described above, there remains considerable uncertainty around the implementation of the HCICO provisions. As a further demonstration of what types of issues are still outstanding, here are some questions we have:

- a. How will a refiner know if a new crude they decide to use is high carbon?
- b. How long will the use of a new crude need to be in order to necessitate the triggering of a carbon determination?
- c. Is a new crude considered high carbon intensity until demonstrated otherwise?
- d. Is the refiner using the crude responsible for the demonstration that the crude is not high carbon intensity? (WSPA4)

Response: The language that sets forth the requirements for treating HCICO was revamped comprehensively based on extensive input from WSPA, member companies and other stakeholders. The modified regulatory text was released in the Second 15-Day Change Notice, which we believe sufficiently addresses the commenter's concerns.

In Resolution 09-31, the Board has directed the staff to develop an informal screening process for assessing the carbon intensity of new or modified fuel pathways. Within this document, staff intends to facilitate the determination of potential high carbon intensity crude oils by working with appropriate stakeholders to establish which crude oil production processes and/or crude oil reservoir characteristics will potentially lead to a crude oil production and transport carbon intensity greater than 15 g CO₂/MJ. Regulated parties using crude oil, which meet these criteria, will be required to establish the carbon intensity using Method 2B (or the Lookup Table if appropriate carbon intensity has already been established). Crude oil, which does not meet the criteria for potential high carbon intensity crude oil, will be assigned the average carbon intensity

shown in the Lookup Table. As stated in Section 95486(a)(3), the regulated parties choice of carbon intensity value is subject in all cases to Executive Officer approval.

With regard to the volume of a new crude oil, the regulation does not specify a threshold that triggers a “carbon determination.” Under the calculations specified in section 95486(b)(2)(A)2.a., the regulated party has to account for all volumes of HCICO and non-HCICO-derived fuels in a calendar year.

With regard to which entity is responsible for demonstrating the a crude is or isn’t a high intensity crude, under section 95486(b)(2)(A)2. that entity is the regulated party since it is the regulated party that must calculate the deficits for CARBOB, gasoline, or diesel fuel, derived wholly or in part from crude oil subject to section 95486(b)(2)(A)2. (i.e., all other CARBOB, gasoline, or diesel fuel, including those derived from HCICO, not otherwise subject to section 95486(b)(2)(A)1.).

IV-176. Comment: The Center again urges ARB to abandon the proposed distinction between conventional and non-conventional fuels in the calculation of carbon intensity values, and to adopt a single set of default values that applies to all petroleum-based fuels. (CNAES2)

Response: The LCFS differentiates between crude oil sources that were used in significant quantities in California in 2006 (e.g. “included in the 2006 California baseline crude mix”) and those crude sources that were not used in significant quantities in 2006. Crude sources, which fall into this latter category, are treated equally as each must undergo a pathway specific carbon intensity determination as they enter the California market. See response to Comments C-238 and C-239.

Waiting on status of legal review of similar 45 day comments - Treatment of Crude oil responses

IV-177. Comment: Our comments throughout the LCFS process have focused on two primary points: (1) the carbon intensity value for all petroleum-based fuels, including the non-conventional fuels, or High Carbon Intensity Crude Oils (HCICO) should be the same; and (2) if not, there must be a “safety valve” mechanism for demonstrating the actual values for the non-conventional fuels, providing appropriate credit for applicable regulatory requirements and other measures to mitigate, offset, or otherwise account for carbon emissions from extraction and processing operations. (CNAES2)

Response: See responses to Comments C-238 and C-239.

IV-178. Comment: The potential GHG reduction benefits of the discriminatory provisions would be negligible. The Department of Energy’s National Energy Technology Laboratory (NETL) recently found that “well-to-tank” (WTT) releases of GHGs contribute only about 20 percent or less to the total lifecycle GHG emissions for each fuel type. Emissions associated with production of non-

conventional crudes are only a small subset of this category for petroleum-based fuels. (CNAES2)

Response: The potential GHG reduction benefits from the HCICO provisions are within the range of the benefits attributable to various other individual elements of the LCFS regulation. See response to comments C-239 and C-242.

IV-179. Comment: U.S. companies are spending billions to modify their facilities to refine and transport Canadian and other heavier crude oil products. The proposed LCFS would severely restrict sales of these fuels in California. The consequences would include more dependence on oil imports from unstable regions, higher fuel prices and a slap in the face to our Canadian neighbors and other valued trading partners. In addition, this approach could cause a net environmental detriment. Foreign production removed from the California market because of the LCFS would be shipped to less regulated markets in other states or countries. (CNAES2)

Response: See responses to Comments C-239, C-240, and C-243.

IV-180. Comment: A primary concept underlying the proposal to adopt a discriminatory LCFS is the notion that fuels derived from unconventional sources are inherently “dirtier” than fuels derived from conventional sources. This common misconception appears to be based on analyses that do not consider promising new technologies or application of mitigation measures or carbon credits or offsets to unconventional fuels operations. The current scientific literature indicates that emissions rates from production of unconventional fuels are extremely uncertain, but can be reduced to levels the same as or lower than conventional fuels when such measures are considered. (CNAES2)

Response: See responses to Comments C-232 and C-239.

IV-181. Comment: Another reason to avoid a discriminatory LCFS is that it would be extremely difficult to administer fairly and effectively. Because the resulting refined products (gasoline and diesel) would carry different carbon intensities downstream, they would no longer be economically fungible. This would lead to substantial uncertainty in the fast moving/low inventory distribution system for transportation fuels, and threaten a consistently adequate supply of fuels in California. In addition, many refinery feedstocks are produced, transported, stored, blended and otherwise altered in ways that may not be readily apparent to those conducting the assessments or auditing the work of producers, brokers and other types of vendors. In this system, domestic producers and those from countries with comprehensive reporting systems would be disadvantaged. Similarly, the focus on the carbon footprint alone would work to the disadvantage of feedstocks with low sulfur content or other environmental advantages but higher emissions of GHGs. These aspects of the proposed system are likely to result in undesirable outcomes such as discrimination in favor of products from

foreign countries with substandard environmental or human rights policies, and against products that have other desirable environmental attributes or emanate from countries with highly developed reporting systems. (CNAES2)

Response: See responses to Comments C-225, C-239, and C-243.

IV-182. Comment: Discrimination among petroleum-based fuels is not necessary to achieve the purposes of the AB 32 program and would in fact be counter-productive. It is not needed to control development of unconventional resources in California, as they are controlled directly by applicable state and federal laws and regulations. The primary effect would be to discourage imports to California of fuels derived from other unconventional resources in North America, such as oil sands in Canada or oil shale in the Western U.S. This would have an inflationary effect on fuel prices in California, as these cost effective North American fuels would not be available. The adverse economic impacts would affect low-income citizens disproportionately, an effect that AB 32 expressly seeks to prevent. (CNAES2)

Response: Response: For information submitted pursuant to the physical-pathway demonstration requirements under section 95484(d)(2), language was added in the Second 15-Day Change Notice to clarify that the details of approved physical pathways would be publicly available in accordance with the requirements of sections 91000-91022, title 17, CCR and the California Public Records Act (Government Code section 6250 et seq.). Further, the originally proposed regulatory text already provided for regulated parties to identify specific information as trade secrets for purposes of submitting a proposed fuel pathway for approval under Method 2A or 2B in section 95486. The originally proposed language already provided for such information to be treated in accordance with the requirements of sections 91000-91022, title 17, CCR and the California Public Records Act (Government Code section 6250 et seq.). For all other information submitted to ARB, no changes were made to the originally proposed regulatory text with regard to the identification and treatment of trade secrets. Therefore, the comment as it pertains to such information falls outside the scope of the First 15-Day Change Notice and requires no further response.

Methods 2A and 2B

IV-183. Comment: It is critical that industry be allowed to proactively provide generic pathways to ARB that reflect the carbon intensity improvements of technology adoption as a means for achieving California's desired results and for catalyzing the adoption of GHG reducing technologies. If these pathways are not predefined, financing and thus realization of these important carbon intensity improvements will impede further development and adoption. (ILCON2)

Response: The rationale for the LCFS regulation's treatment of carbon intensity of CARBOB, gasoline and diesel fuel – including CARBOB, gasoline and diesel fuel

derived from high carbon intensity crude oils not included in the 2006 California baseline crude mix – is set forth in Section II.B.3. Also, see response to Comment C-241.

IV-184. Comment: ARB staff recommended several changes to the carbon intensity Lookup Table based on recently completed additional fuel pathway analyses. We are still reviewing the new pathway GREET documentation used to establish the direct carbon intensity values for the newly established pathways. Overall, we are highly concerned that ARB accepted industry-derived data for development of the two new sugarcane ethanol pathways, but would not accept industry-submitted data for establishment of direct carbon intensity values for other forms of ethanol earlier in the LCFS development process. While we do not question the legitimacy of the data supplied by UNICA, we are questioning ARB's criteria for acceptability and integration of data from stakeholders. There is no rational basis for rejecting the data supplied by RFA10 regarding energy use, co-product generation and other production factors for U.S. ethanol facilities but accepting the data supplied by UNICA regarding co-products and electricity generation for Brazilian ethanol plants. (RFA3)

Response: See response to Comment IV-48.

IV-185. Comment: Second, the intended regulatory status of the August 4 Concept Paper is entirely unclear. If the Concept Paper is a description of how the Executive Officer plans to respond to Method 2 applications, it must be adopted as part of the LCFS regulation. This would require at a minimum that the Executive Officer notice the Concept Paper as a new Modified Text and seek public comment in the manner specified by the APA. Alternatively, if the Concept Paper is intended to have some other purpose, but is still related to the LCFS regulation, then it would constitute material subject to Gov't Code § 11347.1, for which proper notice should have been given to permit full and effective public comment. See, e.g., *In Re Air Resources Board*, OAL File No. 01-1207-02 S (January 30, 2002). These are not mere technical violations of APA requirements; parties involved in the production of low-carbon fuels are likely to have to make early and substantial use of Method 2, and it is important that all aspects of Method 2 be fully developed using the simple but important procedures specified in the APA. (GE4)

Response: The "August 4 Concept Paper" to which the commenter refers is a preliminary draft document entitled "Establishing New Pathways under the California Low Carbon Fuels Standard [--] Procedures and Guidelines for Regulated Parties" "Concept Paper: August 4, 2009," located at http://www.arb.ca.gov/fuels/lcfs/fuels_pw_guidance.pdf. This document is not part of the LCFS regulation or the LCFS rulemaking file, and was not required to be made available pursuant to Gov. Code section 11347.1.

Sections 95485(c) and (d) in the LCFS regulation set forth the criteria for ARB approval of additional carbon intensity values for new sub-pathways under Method 2A, and

entirely new fuel pathways under Method 2B, in response to requests by regulated fuel providers. The August 4 Concept Paper – still in draft form – may ultimately provide regulated parties with additional information that will help them work effectively with ARB to add additional fuel pathways to the LCFS Lookup Table under Methods 2A and 2B. As discussed in Section II.B.2. of this FSOR, originally proposed section 95486(f) has been significantly modified to provide that the Executive Officer can only take final action to approve a carbon intensity value for a modified or new pathway under Method 2A or 2B by conducting a new rulemaking pursuant to applicable provisions of the APA.

The decision by staff to prepare a draft guidelines document is not an indication that the regulatory criteria for approvals of carbon intensity values under Method 2A and 2B are unclear. In any event, the Executive Officer in approving new Method 2 carbon intensity values will not necessarily be bound by the current regulatory criteria – if current provisions turn out to be unclear or incomplete the Executive Officer can revise them as appropriate as part of the rulemaking establishing the new values.

We recognize that under Gov. Code sec. 11340.5 a “guideline” issued by a state agency needs to be adopted as a regulation if it in fact meets the statutory definition of a regulation in Gov. Code sec. 11342.600. If issued in final form – something that has not yet occurred – the guidelines will not be mandatory and therefore will not be a “standard” of general application. Moreover, since a Method 2 approval can only be effectuated by a new rulemaking action subject to the requirements of the APA, any guidelines document will not constrain the regulatory action by the Executive Officer.

Gov. Code section 11347.3 identifies what documents are to be included in the rulemaking file for each rulemaking. This includes “All data and other factual information, technical, theoretical, and empirical studies or reports, if any, on which the agency is relying in the adoption, amendment, or repeal of a regulation” (Gov. Code sec. 11347.3(b)(7).) ARB is not relying on the draft guidance document in this rulemaking. Accordingly, it is not required to be in the rulemaking file.

Gov. Code sec. 11347.1 establishes a mechanism for providing a supplemental 15-day comment period on specified documents where an agency adds the document to the rulemaking file after publication of the hearing notice and relies on the document in proposing the rulemaking action. Since the August 4 guidance document is not in the LCFS rulemaking file and is not being relied upon by ARB in this rulemaking, Gov. Code sec. 11347.1 did not require ARB to make the guidance document available for a supplemental 15-day comment period.

E. Compliance Scenarios

IV-186. Comment: Growth Energy sees no sound reason to question the PRX analysis. Unlike ARB's compliance analysis in Appendix E of the ISOR, the PRX report deals with the competitive status of the specific Midwest corn ethanol pathways in the Lookup Table. If ARB does not agree with the PRX report's analysis of those pathways, it should explain why it does not agree. (GE4)

Response: The PRX report appears to be accurate as far as it goes. The problem with the PRX analysis is that it does not consider the introduction of additional fuels such as cellulosic ethanol and advanced renewable ethanol. In addition, it did not consider the introduction of advanced fuel/vehicle combinations such as battery electric vehicles, fuel cell vehicles and plug-in hybrid vehicles. The purpose of the LCFS is partially to incentivize the introduction of such fuels and fuel/vehicle combinations and to incentivize improvements to reduce the carbon intensity of alternative fuels. The initial values in the Method 1 Lookup Table analyzed by PRX are just that, initial values. Compliance relies on the introduction quantification and inclusion in the Lookup Table of advanced fuels and fuel/vehicle combinations and also the development of improvements that further reduce the carbon intensity of the initial fuel values. The express purpose of including Methods 2A and 2B is to allow this. Had PRX included this in their analysis, they would have found, as ARB did, that compliance with the performance standards is possible.

IV-187. Comment: The new cane ethanol pathways to be included in section 95486 have carbon intensity levels so low that a gasoline supplier could simply blend with cane ethanol, starting in 2011, and achieve compliance with the LCFS standards through 2020. Such a compliance scenario is far more likely than those depicted in Appendix E of the ISOR, which was prepared before the new cane ethanol pathways were announced. (GE4)

Response: The compliance scenarios summarized in Appendix E of the ISOR are only example, hypothetical, possible compliance scenarios that might be used to comply with the LCFS. They are intended only to represent the paths that the staff believes will possibly be used for compliance, based on the current status of development of low carbon fuels. They are intended to show that compliance with the LCFS is possible and feasible. As the development of low carbon intensity fuels advances, it is possible that other compliance pathways and strategies, including the one mentioned by the commenter, will be utilized.

IV-188. Comment: As PRX notes, however, its analysis does not consider whether corn ethanol can be produced competitively in California. Appendix E of the ISOR (the "ISOR") assumes that corn ethanol will, in fact, be produced in California through 2020. There are at least two reasons why the position in Appendix E is incorrect. First, California corn ethanol biorefineries are very likely to be required to purchase and arrange for the transportation of corn from the Midwest. Second, the new cane ethanol pathways give cane ethanol (produced

outside the U.S.) a very significant competitive advantage over California corn ethanol. (GE4)

Response: Appendix E reflects the volume of corn ethanol that was projected to be produced in California at the time of the publication of the ISOR. These representative compliance scenarios were intended to show that fuel providers would be able to reach the 10 percent goal through various means. The sugarcane pathways reflect the best available data and analysis using CA-GREET and GTAP. The supporting documentation was made available online for public review and comment.

IV-189. Comment: Also, there appears to be a bias to electrical autos and outdated biofuels and an opposition to the more practical alternative fuels, in particular, CNG and LNG for consumer autos at gasoline stations. (FISHER3)

Response: There is no bias as suggested by the commenter. The projections for all vehicle numbers (electric, hydrogen, CNG, LNG, etc.) were based on EMFAC analyses, ARB regulations, and other agencies' projections. For more information regarding the data used in the compliance scenarios, please see Appendix E of the ISOR.

F. Environmental Impacts

IV-190. Comment: The Global Warming Solutions Act of 2006 directs ARB to “ensure” that the regulations it adopts do not interfere with the Board’s paramount mission, which is to enable California to achieve and maintain compliance with state and federal air quality standards. It is apparent that the ARB staff has not fully considered the potential increases in smog-forming and toxic emissions that will result from reliance on the electricity pathways. This must be addressed under CEQA and the Board’s implementing regulations by the Board itself, rather than by the Executive Officer. (GE4)

Comment: As indicated in Mr. Lyons’ Declaration accompanying these comments, it is quite clear that the Board has to date failed to consider the impact of the electricity pathways on fleetwide emissions of smog-forming pollutants and toxic air emissions. See Lyons Decl. paragraphs 6-8 and pp.13-18. Growth Energy believes that those effects are “significant,” for purposes of ARB’s mandatory CEQA analysis. When this error is corrected, the impact of the LCFS regulation on volatile organic compound emissions swings from estimated reduction (shown in Table VII-13 of the ISOR) to an increase. *Id.* If the Board or the Executive Officer does not agree that the level of emissions increases estimated by Mr. Lyons are “significant,” Growth Energy believes that the Board or the Executive Officer must state with clarity what level of emissions increases for the relevant smog-forming pollutants and toxic air emissions would be “significant.” (GE4)

Response: The air quality impacts of the electric vehicles included in the LCFS scenarios were analyzed and results included in the Staff Report (Volume II Appendix F8 Motor Vehicle Emissions-Electricity and Hydrogen vs. Gasoline and Diesel). Incorporating ZEV fuels into the LCFS would decrease emissions of criteria pollutants, with a corresponding expected decrease in toxic emissions for all scenarios. Mr. Lyon’s analysis assumes that increased penetration of ZEVs would result in decreased penetration of PZEVs, under the high ZEV penetration scenarios in the LCFS. That could be possible if there were no adjustments to the current ZEV and LEV regulations to account for the new ZEV penetration scenarios. In fact, updates to the ZEV regulation are planned for next year and have already been workshopped. ARB staff will continue to coordinate development of both vehicle and fuels regulation to preserve the benefits of both. See also response to Comment F-12.

On page 13 of Resolution 09-31, the Board designated the Executive Officer as the decision maker for purposes of section 60007, title 17, CCR and responding to environmental issues raised in the LCFS rulemaking. The Executive Officer has made the appropriate environmental findings in Executive Order 09-31.

IV-191. Comment: It is particularly important for the Board to consider those increases in local air pollutants, based on earlier comments prepared for the Western States Petroleum Association (“WSPA”) and filed in the record that demonstrated

that the implementation of the LCFS regulation will not have any perceptible impact on the global climate or the climate of California. If ARB or the Executive Officer does not agree with WSPA's climate impact assessment, then ARB or the Executive Officer must explain why in full detail. From an environmental perspective, the currently proposed rule would require the State to accept increases in local air pollutants in exchange for no measurable positive impact on the climate, if the WSPA analysis is to be credited. (GE4)

Response: The Scoping Plan has many components that in total will reduce GHG emissions within California. The LCFS regulation is an integral part of that plan. The Board, when approving Resolution 90-31 confirmed that: Except for the emissions impacts and water use impacts described above, there are no significant adverse environmental impacts that will occur from the proposed LCFS regulation;

The proposed LCFS regulation is necessary in order to protect public health by substantially reducing GHG emissions resulting from the full fuel lifecycle of transportation fuels in California;

The potential adverse environmental impacts of the proposed LCFS regulation are outweighed by the substantial reduction in GHG emissions and public health benefits that will result from the proposed regulation's adoption and implementation;

The considerations identified above override any adverse environmental impacts that may occur from adoption and implementation of the proposed LCFS regulation; and

The Board has considered alternatives to the proposed regulation and has identified no feasible mitigation measures or alternatives available to the Board that would further substantially reduce the potential adverse impacts of the proposed regulation, as identified above, while at the same time ensuring that the necessary the GHG emission reductions noted herein will be achieved.

See responses to Comments F-10, F-11, F-13 and F-47 in Section F, and E-13-15 in Section E.

IV-192. Comment: An increase in smog-forming and toxic air pollutants is contrary to the requirements of section 38562(b)(4) in the 2006 Act, and would also conflict with other statutory provisions that structure ARB's exercise of its quasi-legislative powers — specifically, its overriding mission to reduce criteria and toxic air pollutants. See, e.g., HSC §§ 39602, 43000, 43010, 43018(a), 43801. The APA provides that “no regulation adopted is valid or effective unless consistent with the statute” that creates the rulemaking power, Gov't Code § 11342.2, but the regulatory modifications now being proposed will cause significant increases in emissions are plainly inconsistent with ARB's enabling statute. OAL will disapprove regulatory revisions that OAL finds to be “beyond the scope of an agency's express or implied rulemaking authority.” See, e.g., Decision Regarding Approval and Partial Disapproval of a Rulemaking Action, *In*

re Department of Conservation, OAL File No. 00-0407-02R (May 22, 2000).
(GE4)

Response: In Resolution 09-31, the Board found that the GHG emission reductions resulting from the implementation of the approved regulation are expected to be real, permanent, quantifiable, verifiable and enforceable by ARB, and the regulation complements and does not interfere with other air quality efforts. More specifically, the Board made the finding in Resolution 09-31 that the approved regulation meets the criteria set forth in section 38562 of the Health and Safety Code.

In adopting regulations pursuant to AB 32 (e.g., the LCFS), the Board is required under HSC section 38562 to ensure, among other things, that activities undertaken to comply with the regulations do not disproportionately impact low-income communities. The originally proposed regulatory text that was approved by the Board at the April 2009 hearing allowed for the use of CCS in cases involving high carbon-intensity crude oil under the specified circumstances (see former section 95486(b)(2)(A)2.c. in Appendix A of the ISOR). That CCS provision was incorporated essentially verbatim into the regulation as approved (see approved section 95486(b)(2)(A)2.a.ii.III). Thus, the Board made the specific finding that the LCFS regulation and activities undertaken to comply with it (including but not limited to the use of CCS) do not result in a disproportionate impact on low-income Californians or low-income communities in California.

Also, see responses to Comments F-13, F-47, and F-52 in Section F, and to Comment E-7 in Section E.

IV-193. Comment: The 2006 Act, in tandem with CEQA, creates significant requirements for ARB to use sound scientific methods and to avoid negative collateral impacts on the Board's paramount mission, which is to improve air quality in California. Thus, the 2006 Act requires the Board to "**ensure**" that its GHG regulations "complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions." See Cal. Health & Safety Code § 38562(b)(4) (emphasis added). (GE4)

Response: See response to Comment above. In short, the Board found that the LCFS does meet HSC 38562, including (b)(4). Also, see responses to Comments F-13, F-47, and F-52 in Chapter F.

IV-194. Comment: In addition, there are important environmental issues arising from the ARB Lookup Table, which essentially makes corn ethanol non-viable as an LCFS compliance pathway over the long term. Regulated parties will be driven to the cane ethanol and electricity pathways over the long term, and may try to comply with the LCFS standards in the early years by making small adjustments in the direct GHG emissions of gasoline itself. This will deprive the public of the

intended maximum benefits of the LCFS regulation, because the full environmental impacts of the cane pathways have not been reflected in the carbon intensity values in the Lookup Table, and the other environmental impacts of the electricity pathway have not been fully considered. (GE4)

Response: In Resolution 09-31, the Board approved that the regulation was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective GHG emission reductions from transportation fuel used in California, and encourage early compliance with the proposed requirements; and

The GHG emission reductions resulting from the implementation of the regulation approved herein are expected to be real, permanent, quantifiable, verifiable, and enforceable by ARB, and the proposed regulation complements, and does not interfere with other air quality efforts.

In regards to the environmental impacts of the electricity pathway, the analysis can be found in the ISOR, pages VII-6 and VII-7.

Also, see responses to Comments F-13, F-47, and F-52 in Chapter F.

IV-195. Comment: The website for LCFS is “full of sound and fury signifying nothing.” It is full of studies, reports, charts and graphs that are too technical for the average layman. With all of the above together with the names and titles of the documentation, there is no association or link to the adverse negative environmental impact that will be the result of failure to implement the LCFS. (FISHER3)

Response: The LCFS is a groundbreaking, science-based regulation that applies the concept of lifecycle assessments to GHG emissions from the production, transportation, marketing, and use of transportation fuels in California. As such, the supporting documentation necessarily must contain highly technical information, data, and reports. With that said, ARB staff endeavored to present the regulation and supporting documentation in plain English to be as comprehensible as possible to lay parties. The environmental impacts analysis for the LCFS rulemaking is presented in extensive detail in pages VII-1 through VII-36 of the ISOR and in Appendix F thereof.

Multimedia Analysis

IV-196. Comment: Given the potentially corrosive properties of ethanol and other biofuels proposed in the Fuel Pathway chart approved at the Board hearing on April 23, 2009, and biofuels presented now for public comment July 20, 2009, a full multimedia analysis for each fuel type is warranted. Recent evidence that ethanol can destroy engines in large numbers enhances ARB’s need and obligation to conduct a thorough multimedia analysis for each fuel type to ensure

compatibility of the fuel mix with all parts throughout the transportation chain as well as assess all environmental harms.

Without a full multimedia review, as legally required under §43830, ARB knowingly risks issues of financial responsibility and state indemnification later in the midst of the State's unprecedented budget crisis. Moreover, ARB knowingly risks imposing substantial environmental harm from unknown effects from numerous fuel types and varieties under ARB's current contemplation.
(MELVER)

Response: The statutory requirements for conducting a multimedia evaluation and how the Board's approval of the LCFS regulation complies with those requirements were discussed extensively in responses to Comments L-21 to L-40 and E-21 to E-32 of the 45-Day Comments.

Other

IV-197. Comment: WSPA believes ARB needs to complete all elements of the regulation before, 1) proceeding with any adoption hearing in the first instance, and 2) requiring regulated parties to initiate efforts to comply. We do not believe it is appropriate for ARB to hold an adoption hearing and then proceed to continue to work major aspects of the regulation in following months in piecemeal fashion.

Examples of items that need much more clarity in order for the regulation to be complete include: recordkeeping and reporting requirements; credit trading details; the role of ARB in credit trading markets; the treatment of high carbon intensity crude oil (HCICO); and confidentiality provisions. Without additional clarity on these issues, our industry still does not have the tools it needs to move forward with compliance efforts.

Reporting requirements begin in four months and our members need to be initiating activity on many aspects of the regulation now, not in 2010. We understand that some elements of the regulation that the Board will need to address will not occur until the spring of 2010. This fails to be an acceptable or admirable rulemaking process. (WSPA4)

Response: The adopted LCFS regulations require that all regulated parties report fuels and other data electronically and on a quarterly and annual basis. The first reports are not due until May 31, 2010. There should be sufficient time for WSPA members to complete their reporting and recordkeeping requirements between when the requirements are released and when the information is due. In regards to the role of ARB in credit trading markets, see the ISOR, Section V, pages V-35 to V-36. The treatment of HCICO will be handled by method 2B. Please see ISOR, Section IX, Page IX-3 to IX4. ARB must follow state regulations regarding business confidential information.

IV-198. Comment: I recommend that the Board Adopt an Emergency Regulation.
(FISHER1, FISHER2)

Response: ARB is authorized to amend a regulation on an emergency basis only upon a finding that the amendment is necessary for the immediate preservation of the public health and safety or general welfare, and in any event an emergency regulation cannot be operative for more than 180 days unless ARB complies with all APA requirements (Government Code section 11346.1). The approach taken in this rulemaking is preferable.

F. Environmental Impacts

IV-199. Comment: The Global Warming Solutions Act of 2006 directs ARB to “ensure” that the regulations it adopts do not interfere with the Board’s paramount mission, which is to enable California to achieve and maintain compliance with state and federal air quality standards. It is apparent that the ARB staff has not given full consideration to the potential increases in smog-forming and toxic emissions that will result from reliance on the electricity pathways. This must be addressed under CEQA and the Board’s implementing regulations by the Board itself, rather than by the Executive Officer. (GE4)

Comment: As indicated in Mr. Lyons’ Declaration accompanying these comments, it is quite clear that the Board has to date failed to consider the impact of the electricity pathways on fleetwide emissions of smog-forming pollutants and toxic air emissions. See Lyons Decl. paragraphs 6-8 and pp.13-18. Growth Energy believes that those effects are “significant,” for purposes of ARB’s mandatory CEQA analysis. When this error is corrected, the impact of the LCFS regulation on volatile organic compound emissions swings from estimated reduction (shown in Table VII-13 of the ISOR) to an increase. *Id.* If the Board or the Executive Officer does not agree that the level of emissions increases estimated by Mr. Lyons are “significant,” Growth Energy believes that the Board or the Executive Officer must state with clarity what level of emissions increases for the relevant smog-forming pollutants and toxic air emissions would be “significant.” (GE4)

Response: The air quality impacts of the electric vehicles included in the LCFS scenarios were analyzed and results included in the Staff Report (Volume II Appendix F8 Motor Vehicle Emissions-Electricity and Hydrogen vs. Gasoline and Diesel). Incorporating ZEV fuels into the LCFS would decrease emissions of criteria pollutants, with a corresponding expected decrease in toxic emissions for all scenarios. Mr. Lyon’s analysis assumes that increased penetration of ZEVs would result in decreased penetration of PZEVs, under the high ZEV penetration scenarios in the LCFS. That could be possible if there were no adjustments to the current ZEV and LEV regulations to account for the new ZEV penetration scenarios. In fact, updates to the ZEV regulation are planned for next year and have already been workshopped. ARB staff will continue to coordinate development of both vehicle and fuels regulation to preserve the benefits of both. See also response to Comment F-12.

On page 13 of Resolution 09-31, the Board designated the Executive Officer as the decision maker for purposes of section 60007, title 17, CCR and responding to environmental issues raised in the LCFS rulemaking. The Executive Officer has made the appropriate environmental findings in Executive Order 09-31.

IV-200. Comment: It is particularly important for the Board to consider those increases in local air pollutants, based on earlier comments prepared for the Western States Petroleum Association (“WSPA”) and filed in the record that demonstrated

that the implementation of the LCFS regulation will not have any perceptible impact on the global climate or the climate of California. If ARB or the Executive Officer does not agree with WSPA's climate impact assessment, then ARB or the Executive Officer must explain why in full detail. From an environmental perspective, the currently proposed rule would require the State to accept increases in local air pollutants in exchange for no measurable positive impact on the climate, if the WSPA analysis is to be credited. (GE4)

Response: The Scoping Plan has many components that in total will reduce GHG emissions within California. The LCFS regulation is an integral part of that plan. The Board, when approving Resolution 90-31 confirmed that: Except for the emissions impacts and water use impacts described above, there are no significant adverse environmental impacts that will occur from the proposed LCFS regulation;

The proposed LCFS regulation is necessary in order to protect public health by substantially reducing GHG emissions resulting from the full fuel lifecycle of transportation fuels in California;

The potential adverse environmental impacts of the proposed LCFS regulation are outweighed by the substantial reduction in GHG emissions and public health benefits that will result from the proposed regulation's adoption and implementation;

The considerations identified above override any adverse environmental impacts that may occur from adoption and implementation of the proposed LCFS regulation; and

The Board has considered alternatives to the proposed regulation and has identified no feasible mitigation measures or alternatives available to the Board that would further substantially reduce the potential adverse impacts of the proposed regulation, as identified above, while at the same time ensuring that the necessary the GHG emission reductions noted herein will be achieved.

See responses to Comments F-10, F-11, F-13 and F-47 in Section F, and E-13-15 in Section E.

IV-201. Comment: An increase in smog-forming and toxic air pollutants is contrary to the requirements of section 38562(b)(4) in the 2006 Act, and would also conflict with other statutory provisions that structure ARB's exercise of its quasi-legislative powers -- specifically, its overriding mission to reduce criteria and toxic air pollutants. See, e.g., HSC §§ 39602, 43000, 43010, 43018(a), 43801. The APA provides that "no regulation adopted is valid or effective unless consistent with the statute" that creates the rulemaking power, Gov't Code § 11342.2, but the regulatory modifications now being proposed will cause significant increases in emissions are plainly inconsistent with ARB's enabling statute. OAL will disapprove regulatory revisions that OAL finds to be "beyond the scope of an agency's express or implied rulemaking authority." See, e.g., Decision Regarding

Approval and Partial Disapproval of a Rulemaking Action, *In re Department of Conservation*, OAL File No. 00-0407-02R (May 22, 2000). (GE4)

Response: In Resolution 09-31, the Board found that the GHG emission reductions resulting from the implementation of the approved regulation are expected to be real, permanent, quantifiable, verifiable and enforceable by ARB, and the regulation complements and does not interfere with other air quality efforts. More specifically, the Board made the finding in Resolution 09-31 that the approved regulation meets the criteria set forth in section 38562 of the Health and Safety Code.

In adopting regulations pursuant to AB 32 (e.g., the LCFS), the Board is required under HSC section 38562 to ensure, among other things, that activities undertaken to comply with the regulations do not disproportionately impact low-income communities. The originally proposed regulatory text that was approved by the Board at the April 2009 hearing allowed for the use of CCS in cases involving high carbon-intensity crude oil under the specified circumstances (see former section 95486(b)(2)(A)2.c. in Appendix A of the ISOR). That CCS provision was incorporated essentially verbatim into the regulation as approved (see approved section 95486(b)(2)(A)2.a.ii.III). Thus, the Board made the specific finding that the LCFS regulation and activities undertaken to comply with it (including but not limited to the use of CCS) do not result in a disproportionate impact on low-income Californians or low-income communities in California.

Also, see responses to Comments F-13, F-47, and F-52 in Section F, and to Comment E-7 in Section E.

IV-202. Comment: The 2006 Act, in tandem with CEQA, creates significant requirements for ARB to use sound scientific methods and to avoid negative collateral impacts on the Board's paramount mission, which is to improve air quality in California. Thus, the 2006 Act requires the Board to "**ensure**" that its GHG regulations "complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions." See Cal. Health & Safety Code § 38562(b)(4) (emphasis added). (GE4)

Response: See response to Comment above. In short, the Board found that the LCFS does meet HSC 38562, including (b)(4). Also, see responses to Comments F-13, F-47, and F-52 in Chapter F.

IV-203. Comment: In addition, there are important environmental issues arising from the ARB Lookup Table, which essentially makes corn ethanol non-viable as an LCFS compliance pathway over the long term. Regulated parties will be driven to the cane ethanol and electricity pathways over the long term, and may try to comply with the LCFS standards in the early years by making small adjustments in the direct GHG emissions of gasoline itself. This will deprive the public of the

intended maximum benefits of the LCFS regulation, because the full environmental impacts of the cane pathways have not been reflected in the carbon intensity values in the Lookup Table, and the other environmental impacts of the electricity pathway have not been fully considered. (GE4)

Response: In Resolution 09-31, the Board approved that the regulation was developed using the best available economic and scientific information and will achieve the maximum technologically feasible and cost-effective GHG emission reductions from transportation fuel used in California, and encourage early compliance with the proposed requirements; and

The GHG emission reductions resulting from the implementation of the regulation approved herein are expected to be real, permanent, quantifiable, verifiable, and enforceable by ARB, and the proposed regulation complements, and does not interfere with other air quality efforts.

In regards to the environmental impacts of the electricity pathway, the analysis can be found in the ISOR, pages VII-6 and VII-7.

Also, see responses to Comments F-13, F-47, and F-52 in Chapter F.

IV-204. Comment: The website for LCFS is “full of sound and fury signifying nothing.” It is full of studies, reports, charts and graphs that are too technical for the average layman. With all of the above together with the names and titles of the documentation, there is no association or link to the adverse negative environmental impact that will be the result of failure to implement the LCFS. (FISHER3)

Response: The LCFS is a groundbreaking, science-based regulation that applies the concept of lifecycle assessments to GHG emissions from the production, transportation, marketing, and use of transportation fuels in California. As such, the supporting documentation necessarily must contain highly technical information, data, and reports. With that said, ARB staff endeavored to present the regulation and supporting documentation in plain English to be as comprehensible as possible to lay parties. The environmental impacts analysis for the LCFS rulemaking is presented in extensive detail in pages VII-1 through VII-36 of the ISOR and in Appendix F thereof.

Multimedia Analysis

IV-205. Comment: Given the potentially corrosive properties of ethanol and other biofuels proposed in the Fuel Pathway chart approved at the Board hearing on April 23, 2009, and biofuels presented now for public comment July 20, 2009, a full multimedia analysis for each fuel type is warranted. Recent evidence that ethanol can destroy engines in large numbers enhances ARB’s need and obligation to conduct a thorough multimedia analysis for each fuel type to ensure

compatibility of the fuel mix with all parts throughout the transportation chain as well as assess all environmental harms.

Without a full multimedia review, as legally required under §43830, ARB knowingly risks issues of financial responsibility and state indemnification later in the midst of the State's unprecedented budget crisis. Moreover, ARB knowingly risks imposing substantial environmental harm from unknown effects from numerous fuel types and varieties under ARB's current contemplation.
(MELVER)

Response: The statutory requirements for conducting a multimedia evaluation and how the Board's approval of the LCFS regulation complies with those requirements were discussed extensively in responses to Comments L-21 to L-40 and E-21 to E-32 of the 45-Day Comments.

Other

IV-206. Comment: WSPA believes ARB needs to complete all elements of the regulation before, 1) proceeding with any adoption hearing in the first instance, and 2) requiring regulated parties to initiate efforts to comply. We do not believe it is appropriate for ARB to hold an adoption hearing and then proceed to continue to work major aspects of the regulation in following months in piecemeal fashion.

Examples of items that need much more clarity in order for the regulation to be complete include: recordkeeping and reporting requirements; credit trading details; the role of ARB in credit trading markets; the treatment of high carbon intensity crude oil (HCICO); and confidentiality provisions. Without additional clarity on these issues, our industry still does not have the tools it needs to move forward with compliance efforts.

Reporting requirements begin in four months and our members need to be initiating activity on many aspects of the regulation now, not in 2010. We understand that some elements of the regulation that the Board will need to address will not occur until the spring of 2010. This fails to be an acceptable or admirable rulemaking process. (WSPA4)

Response: The adopted LCFS regulations require that all regulated parties report fuels and other data electronically and on a quarterly and annual basis. The first reports are not due until May 31, 2010. There should be sufficient time for WSPA members to complete their reporting and recordkeeping requirements between when the requirements are released and when the information is due. In regards to the role of ARB in credit trading markets, see the ISOR, Section V, pages V-35 to V-36. The treatment of HCICO will be handled by method 2B. Please see ISOR, Section IX, Page IX-3 to IX4. ARB must follow state regulations regarding business confidential information.

IV-207. Comment: I recommend that the Board Adopt an Emergency Regulation.
(FISHER1, FISHER2)

Response: ARB is authorized to amend a regulation on an emergency basis only upon a finding that the amendment is necessary for the immediate preservation of the public health and safety or general welfare, and in any event an emergency regulation cannot be operative for more than 180 days unless ARB complies with all APA requirements (Government Code section 11346.1). The approach taken in this rulemaking is preferable.

V. SUMMARY OF COMMENTS MADE DURING THE SECOND 15-DAY COMMENT PERIOD AND RESPONSES

The table below identifies the 18 comments received during the second 15-day comment period. It provides a correlation between (1) the abbreviation used in this Section V to refer to a comment letter; (2) the number assigned to the comment letter in the listing (with links) on ARB's website for this rulemaking of all written comments received in the rulemaking; and (3) the name of the person(s) signing the comment letter and the date received by ARB.

Abbreviation	Letter #	Commenter
11GENRGY	14	Claire Van Zuiden* and Frederick C. Berndt, 11 Good Energy Written testimony: October 08, 2009
A204NESTE5	13	Cal Hodge, A2O Inc. on behalf of Neste Oil Written testimony: October 08, 2009
ALEX3	4	Charles Alexander Written testimony: October 06, 2009
BAILEY	2	Michael Bailey, People First Written testimony: September 27, 2009
BIO2	11	Stephanie Batchelor* and Brent Erickson, Biotechnology Industry Organization Written testimony: October 08, 2009
CANOPY	6	John Thomas, Canopy Prospecting, Inc. and Erik Johnson, Trinidad Dehydration Company Limited Written testimony: October 07, 2009
CATERPILLAR	15	James P. Halloran, Caterpillar Inc. Written testimony: October 08, 2009
CNGVC4	17	Pete Price, California Natural Gas Vehicle Coalition Written testimony: October 08, 2009
COBALT	5	• Steven Shevick* and Rick Wilson, Cobalt Biofuels Written testimony: October 07, 2009
CONOCO3	8	H. Daniel Sinks, ConocoPhillips Written testimony: October 08, 2009
GE6	12	Tom Buis, Growth Energy Written testimony: October 08, 2009
MELVER2	7	Naomi Molver Written testimony: October 08, 2009
POET3	10	Mark Stowers, POET Written testimony: October 08, 2009
SEMPRA5	19	Michael Murray, Sempra Energy Written testimony: October 08, 2009

Abbreviation	Letter #	Commenter
TESORO4	9	Jack Bean, Tesoro Corporation Written testimony: October 09, 2009
UNICA3	1	Joel Velasco, Brazilian Sugarcane Industry Association Written testimony: September 25, 2009
UNICA4	18	Joel Velasco, Brazilian Sugarcane Industry Association Written testimony: October 08, 2009
WSPA5	16	Gina Grey* and Catherine Reheis-Boyd, WSPA Written testimony: October 08, 2009

* Submitter, not signatory

The Second 15-Day Change Notice was issued September 23, 2009 with an October 8, 2009 comment deadline. It solicited comment only on the limited number of additional regulatory modifications being made available, one additional document being added to the rulemaking record, and slightly modified versions of six pathway documents. The regulatory modifications consisted of:

- (1) Changes to section 95484(a)(1)(B), (a)(1)(C), and (a)(2)(B) regarding requirements for regulated parties, primarily related to how requirements apply to HCICO-derived fuels;
- (2) Changes to section 94584(c)(3)(A)1. and 3. on submittals of product transfer documents and reporting for HCICO-derived fuels;
- (3) Changes to section 95484(d)(2) on demonstration of physical pathways;
- (4) Changes to section 5486(a) (Selection of Method for Determining Carbon Intensity) to provide that a regulated party's choice of carbon intensity value is subject to approval by the Executive Officer and specify the process for the Executive Officer's review;
- (5) Changes to several pathways for LNG in the Carbon Intensity Lookup Tables, Tables 6 and 7, in section 95486(b)(1);
- (6) Several minor modifications to Tables 6 and 7 in section 95486(b) to reflect updates and corrections to the pathway documents that support the values in the tables or to clarify the pathways that were used to generate several "average" pathways; and
- (7) Modifications to the language in section 95486(b)(2)(A)2. governing the deficit treatment of CARBOB, gasoline, or diesel fuel derived from HCICO.

Despite the Second 15-Day Change Notice's statement that "only comments relating to the modifications to the text of the regulation or to the additional documents and information referenced above shall be considered by the Executive Officer," several parties submitted comments on other topics not covered by the Notice. Comments on such other topics are generally not summarized or responded to in this Section V. of the

FSOR. This includes comments in WSPA5 on sections 95481(a)(24), 95484(c)(3)(A)4., 95484(d)(1), 95485(a)(3)(C) (modifications change formatting only), 95485(c)(1)(B) and on ARB's release of a modified Executive Summary for the LCFS ISOR that is not part of the rulemaking record and is not being relied upon; comments in A204NESTE5 on sections 95487(c)(3) and (c)(3)(B), and on section 95485(a)(1) Table 4; comments in POET3 on the corn ethanol pathway; the comments in TESORO4 on "intensification" of crop production and availability of "low carbon" alternatives, and on the Brazilian cane ethanol carbon intensity value from land use change; comments in COBALT pertaining to butanol and biobutanol; and comments in CANOPY on the 5 gram substantiality requirement.

This Section V also does not summarize or address "new information and analyses concerning the Global Trade Analysis Project [GTAP] model" submitted in GE6. This included material presented to the National Corn Growers Association (NCGA) in late August by Prof. Wallace Tyner and parties at ORNL. The Second 15-Day Change Notice did not solicit additional comment on the GTAP model. ARB does not consider this additional information and analyses to be part of the record upon which the rulemaking is based. Staff has nevertheless reviewed the material and has determined it would not affect the LCFS regulations adopted in this rulemaking.

Additionally, this Section V does not summarize or respond to comments supporting various elements made available for comment by the Second 15-Day Change Notice, including UNICA4's support of the modifications pertaining to the ethanol from sugarcane pathways, CNGVC4's support of modifications made pertaining to the LNG pathways, BAILEY's support in general, and CONOCO3's support of the recent development of a pathway for renewable diesel produced from tallow and modifications regarding the handling of product transfer documents. COBALT and 11GENRGY supported ARB's approach of establishing an Expert Workgroup on analyzing land use and indirect effects.

Despite falling outside the scope of the Second 15-Day Change Notice, a number of comments nevertheless are summarized and responded to, as noted below. Although ARB legally is not required to summarize and respond to these comments under the APA, we provided a response to these comments because it was felt the general public and interested stakeholders could benefit from the additional clarity provided by the responses.

A. Regulatory

Reporting Tools

V-1. Comment: Page 37 of Modified Regulation Order 9/23/09, Recordkeeping and Auditing:

(1) A regulated party must retain all of the following records for at least 3 years and must provide such records within 20 days of a written request received from the Executive Officer (E.O.) or his/her designee before expiration of the period during which the records are required to be retained.

(2) On page 26 it indicates that ARB's electronic reporting tool will be available in early 2010 (not before) – another indication on how incomplete the rulemaking is. Our understanding is the tool will be available before the New Year. If it will not be available until early in the New Year, then this raises a significant concern. (WSPA5)

Response: It is expected that an XML Schema Document (XSD) will be available to regulated parties by the end of November 2009. The XML Schema Document will provide the LCFS regulated parties with the detailed description of the data elements required in their LCFS compliance reports. An online application is expected by January 2010 that will provide a means for regulated parties to submit test files for processing. Regulated parties will be able to review results from file processing, make modifications in their test data file(s) and re-submit well before the first submittal deadline of May 31, 2010.

V-2. Comment: First, we are concerned regarding the lack of registration requirements for the biofuel producers to define the carbon intensity of their products. As purchasers of their products we need assurance that the carbon intensity of each product has been determined and accepted by ARB, and that the demonstration of a physical pathway (needed for credit generation in 2011) has also been accepted by ARB. (WSPA5)

Response: A process is being developed to register biofuel producers in the LCFS program for those producers wanting to market their biofuels in California and wishing to register. As part of the registration process, the producer will provide the refinery location and the fuel pathway (energy source, conversion technology, etc.) to establish a carbon intensity value. A description of the physical pathway for the transportation of the biofuel to California will be included in the registration.

The ARB will confirm the carbon intensity value based on the information supplied by the producer. More detailed spot checks will be made to further confirm the accuracy of the information supplied to support the selected carbon intensity. Regulated parties are ultimately responsible for the correctness of the carbon intensity of the biofuels they purchase and the carbon intensity data reported.

V-3. Comment: The rule requires we report compliance using an ARB electronic reporting tool which has not yet been developed and is not expected until after 1Q10. Although many reporting requirements are specific and in the rule, many of the detailed expectations of the Compliance & Reporting Tool (CRT) will not be known until the CRT is final. It is unreasonable to expect that systems be built to collect and manage the data before the CRT is in use or can be tested.

Perhaps it would be more reasonable if we all “beta” test the CRT in the quarter following its final beta version release. Given this rule is very complex and many of the regulated parties are those who have never before been subject to ARB regulation, ARB should have developed and rolled out a series of Compliance Workshops for interested regulated parties well in advance of any upcoming compliance dates. No such action has yet been taken. (WSPA5)

Response: Contrary to the commenter’s contention, staff has held a series of workshops and public meetings in which the LCFS Reporting Tool (LRT) (formerly known as the CRT) was discussed in increasing detail. Staff held at least five public workshops and workgroup meetings from December 2007 through August 2009. The discussion of the LRT evolved from general concepts to highly detailed screenshots of the nearly-complete LRT software that is now undergoing internal shakedown testing. During these meetings, staff invited and accepted volunteer participants from the industry to serve as “beta” testers or otherwise provide feedback on the software being developed. Based on the current development trajectory, staff anticipates the LRT will be available for use by regulated parties in early 2010. This should provide ample time for regulated parties to use and familiarize themselves with the LRT in 2010 before the LCFS carbon-intensity compliance schedule becomes effective in January 2011.

V-4. Comment: Many of these newly regulated parties as well as many organizations who have long been regulated by ARB are “in the dark” concerning upcoming deadlines and requirements. It is unreasonable to expect regulated parties to comply in the first quarter under these conditions.

WSPA proposes that ARB work with WSPA and other regulated parties to develop a 2010 protocol that allows regulated parties to use “best available data” to assign carbon intensities and designate pathways. “Best available” could be defined as allowing regulated parties to make carbon intensity assignments or make pathway designations from ARB’s website based on verbal or written feedback from suppliers in order to give maximum flexibility. (WSPA5)

Response: The principal deadlines and requirements of the LCFS program have been unchanged since the 45-day comment period began on March 6, 2009. In addition, most of the substantive requirements have remained unchanged since the January 29, 2009 draft version of the regulation was released for public review and comment. Since 2007, staff held 15 public workshops and meetings to discuss various aspects of the LCFS regulation, and preliminary versions of the regulation were released in late 2008

and early 2009 on four separate occasions prior to the start of the 45-day comment period. Given the staff's extraordinary efforts to work closely with the stakeholders, one wonders how the stakeholders could have been "in the dark" with respect to the deadlines and requirements.

Nevertheless, staff is open to discussing ways in which to develop, compile, and report the information required to be submitted, provided such information is submitted in accordance with the regulatory requirements. Under specified conditions, the regulation also permits the Executive Officer to enter into enforceable protocols with regulated parties for the reporting, recordkeeping, and demonstration of pathway requirements (see section 95490). At this time, there is no compelling reason to incorporate the suggested concepts into the regulatory text, especially given the lack of specificity in the commenter's suggestion. But as part of the two formal reviews built into the regulation, the Executive Officer may consider whether it is appropriate to propose amendments to the regulation in the future to "flesh out" and incorporate the concepts outlined by the commenter.

Section 95484

V-5. Comment: Page 14, Section 95484 (a)(1)(B)(2)(a) – Requirements for Regulated Parties:

WSPA requests the following text changes be made to several sections in the modified text:

a. the volume and average carbon intensity of the transferred CARBOB. For a transferor that is a regulated party subject to section 95486(b)(2)(A)2., the transferor of CARBOB may report as the "average carbon intensity" on the product transfer document the [total DELETE] carbon intensity value for CARBOB based on average crude oil delivered to CA refineries ADD as shown in the Carbon Intensity Lookup Table;

Page 16, Section 95484 (a)(1)(B)(5)(a) – same revisions as shown above.

Page 18, Section 95484 (a)(1)(D)(3)9a) – same revisions as above.

Page 20, Section 95284 (a)(2)(B)(2)(a) – same revisions as above.

Page 22, Section 95484 (a)(2)(B)(5)(a) – same revisions as above. (WSPA5)

Response: The commenter appears to misunderstand the nature of the modified regulatory text. The reference to "total carbon intensity" of CARBOB simply means the regulated party is to report on the Product Transfer Document the total carbon intensity value for CARBOB shown in Table 6. Table 6 shows the total carbon intensity value for CARBOB as 95.86 g CO₂-eq/MJ, which is the sum of the "direct emissions" value (95.96) and the "land use or other indirect effect" value (0.00). The pathway description in Table 6 already recognizes that the pathway for CARBOB reflects a carbon intensity value "based on the average crude oil delivered to California refineries and average

California refinery efficiencies.” Therefore, there is no need to make the suggested change to the regulatory text.

It should be noted that the provision described above applies only to regulated parties for petroleum products derived from HCICO. This was done in recognition of the practical difficulties in identifying the HCICO carbon intensity on each batch’s Product Transfer Document; instead, the modified regulatory text specifies how the HCICO carbon intensity values would be identified and reconciled in the LCFS Reporting Tool as part of the periodic reporting requirements.

V-6. Comment: Page 38 – Section 95484 (d)(2)(C) - Initial Demonstration of Delivery Methods reads: *The documentation must include a map(s) that shows the truck/rail lines or routes, pipelines, transmission lines, and other delivery methods (segments) that, together, comprise the physical pathway. If more than one company is involved in the delivery, each segment on the map must be linked to a specific company that is expected to transport the fuel through each segment of the physical pathway. The regulated party must provide the contact information for each such company, including the contact name, mailing address, phone number, and company name.*

WSPA recognizes staff has made some revisions to this section based on comments we provided during the 30 day package review period. However, we continue to believe the information required by ARB is still far too detailed for the objective and could be counter productive by discouraging or delaying parties from registering physical pathways.

For example, the requirement indicates that the regulated party must provide the contact information including the contact name, mailing address, phone number and company name for companies involved in each segment of the fuel pathway. This would likely require the regulated party to list every possible company that could be involved either currently or in the future in order to cover all contingencies, or will require constant revisions as contracts with companies (such as various trucking companies) are changed over time.

We do not see the need for such detailed information when such changes are not, by ARB’s definition, considered material. At a minimum, we recommend that if such detailed information is needed it should be upon request only. (WSPA5)

Response: The commenter appears to be referring to a change made to the text in section 95484(d)(2)(C) that was merely grammatical and nonsubstantive. The originally proposed language,

“The regulated party must provide the name, mailing address, phone number, and company name for each such person.”

was modified to read,

“The regulated party must provide the contact information for each such company, including the contact name, mailing address, phone number, and company name.”

While the wording sequence was changed and “person” was changed to “company,” the intent of the originally proposed language remains unchanged. Simply put, the level of detail set forth in the originally proposed and modified regulatory text is necessary in order for ARB enforcement staff to verify a physical pathway submitted under the LCFS program. Without this information, it would be difficult for our enforcement staff to verify that a fuel or blendstock traversed the route specified by a regulated party or non-regulated party fuel provider.

With regard to how often the information described above must be supplied to the Executive Officer, the regulatory text as modified requires the information only during the initial demonstration phase, unless a material change (i.e., change in a mode of transportation) occurs. In that case, the contact information for the company that will implement the change in mode of transportation would need to be provided to ARB within 30 business days, as specified in the modified text in section 95484(d)(2)(F). Based on these reasons, we do not believe it is necessary to change the language to an as-requested basis.

V-7. Comment: Page 39 – Section 95484 (d)(2)(F) Subsequent Demonstration of Physical Pathway reads:

If there is a material change to an approved physical pathway demonstration, the regulated party must notify the Executive Officer in writing within 30 business days after the material change has occurred, and the approved physical pathway shall become invalid 30 business days after the material change has occurred.

WSPA previously discussed this process with ARB staff and understood staff was in agreement that material changes could be submitted with the quarterly report and did not need to be submitted on an ad hoc basis – in the current version, after 30 business days. WSPA requests this be altered to reflect that revisions can be submitted with the quarterly report.

In addition, the text states the approved physical pathway shall become invalid after 30 days. WSPA strongly disagrees with the possibility that previous pathways would become invalid – both due to the fact that other parties may be utilizing that pathway so it would put that pathway in jeopardy, as well as the fact a party may wish to return to the original pathway without having to recreate it. In other words, approval of physical pathways should be evergreen. (WSPA5)

Response: With regard to the change from 5 to 30 business days for reporting a material change, the quarterly reporting of material changes was considered, as noted by the commenter. However, after further consideration, it was determined that the quarterly reporting of a material change in a physical pathway would be inadequate for

ensuring that the LCFS is functioning properly. This is because the quarterly reporting of a material change would provide ARB enforcement and auditing staff insufficient time to determine if the material change is of such magnitude as to affect the issuance of a claimed LCFS credit. As set forth in section 95485(b), the issuance of LCFS credits will be done on a quarterly basis. Therefore, if material changes are also reported quarterly, an LCFS credit may be issued in one quarter and then shortly afterward ARB staff may discover that the credit is not in fact supportable because of the material change.

With regard to the invalidation of a previously approved physical pathway in which a material change occurs, the language referred to by the commenter was added under the First 15-Day Change Notice but was not modified under the Second 15-Day Change Notice. Therefore, this portion of the comment falls outside the scope of the Second 15-Day Change Notice and requires no further response.

V-8. Comment: Page 39 – Section 95484 (d)(2)(G) Submittal and Review of and Final Action on Submitted Demonstrations reads:

The regulated party may not receive credit for any fuel or blend stock until the Executive Officer has approved the regulated party's submitted physical-pathway demonstration pursuant to section 95484(d)(2)(C) through (E). Upon receiving Executive Officer approval of a physical pathway, the regulated party may claim LCFS credits based on that pathway that are calculated retroactive to the date when the regulated party's use of the pathway began but no earlier than January 1, 2011.

WSPA's first question on this section concerns what is required for physical pathway approvals in 2010. Since 2010 is a reporting year and physical pathway approval is required to generate credit, does this imply that physical pathways need to be approved by January 1, 2011? If this is the case, it could result in delays by producers/importers in filing physical pathway demonstrations. Given the requirement of demonstration of physical pathways in order to generate LCFS credits, ARB should be encouraging the demonstration of physical pathways by producers, importers and marketers as soon as practical. WSPA5)

Response: Physical pathways do not need to be approved by January 1, 2011. But a regulated party may not generate credits under section 95485(b) until it has demonstrated or provided a demonstration of a physical pathway under section 95484(d)(2). And the originally proposed language did not provide authority to process such demonstrations until January 1, 2011. Because of this, section 95480.1(a) was modified under the First 15-Day Change Notice to specify that section 95484(d) goes into effect on January 1, 2010. The result of the modification is that ARB staff can review and process physical pathway demonstrations any time after January 1, 2010. Had the regulatory text not been changed, the originally proposed language would have left little time for the Executive Officer to approve physical pathways before the first quarter of 2011 when the credits are due to start being issued.

The change allowing ARB staff to begin processing physical pathway demonstrations after January 1, 2010 should encourage producers, importers, and marketers to submit and obtain approval of their physical pathway demonstrations as soon as practical.

V-9. Comment: Alternately, if ARB's intent is to require demonstration of physical pathway by January 1, 2010, given there is no precedent and with the uncertainty in the demonstration of physical pathway requirements, it is unrealistic to expect producers/importers to be in a position to submit and gain approval of physical pathways by January 1, 2010.

Clarity on the process is needed. We re-iterate our prior comment that to provide guidance to industry, we recommend that ARB publish an example of a physical pathway demonstration that would be acceptable to the Executive Officer. (WSPA5)

Response: As noted in the previous response, physical pathway demonstrations are not required by January 1, 2010; rather, they are allowed to be submitted and processed as of January 1, 2010. Regulated parties will have a year (2010) to get their demonstrations approved before credits are due to be issued in 2011. Having said that, we believe there is merit in publishing examples of physical pathway demonstrations. To this end, ARB staff intends to work with regulated parties and other stakeholders to develop sample pathway demonstrations for publication on ARB's website.

V-10. Comment: By modifying the definition of "material change" to an approved physical pathway to only include changes in the basic mode of transportation for the fuel, ARB may miss significant changes in GHG emissions from other changed processes, such as biorefineries switching from coal to other energy sources such as biomass incineration that may release ~50 percent more CO₂ emissions than coal (see the attachment by the Massachusetts Environmental Energy Alliance.) Changes in other production processes and technology, updated science, etc., warrants a broader definition of "material change" to include all changes that will result in an increase of GHG emissions in order for emissions reductions to be real, enforceable, quantifiable, and permanent as legally required. Because biomass incineration can emit ~50 percent more CO₂ emissions than coal, ARB should not develop a fuel pathway nor encourage forest biomass as an energy source as alluded to in the LCFS Update released on October 6, 2009. (MELVER2)

Response: The commenter appears to misunderstand the "demonstration of physical pathway" provisions in section 95484(d)(2). These provisions are intended to require a demonstration that a fuel or blendstock actually makes it or is likely to make it to California from wherever it is produced outside of California. This basically requires a demonstration of a physical route to California and a method or methods of transporting a fuel over that route. Thus, the modification with regard to "material change" deals with changes to a basic mode of transporting a fuel to California in an approved physical

pathway (e.g., changing an approved physical route from rail transport to truck-based would constitute a material change).

By contrast, the commenter appears to be referring to changes in a fuel's full lifecycle carbon intensity. Rather than a route, a fuel's carbon intensity is calculated using the metric of "grams CO₂ equivalent per megajoule" and are set forth in the Carbon Intensity Lookup Tables (Tables 6 and 7 in section 95486). As such, the carbon intensity associated with a fuel's lifecycle pathway is fundamentally different from the physical pathway by which that fuel is transported to California.

With regard to fuel pathways derived from forest biomass, no such pathways have been included in Tables 6 or 7. Fuel and energy derived from forest biomass is a contentious issue, and in Resolution 09-31 the Board directed the Executive Officer to work with the Interagency Forest Work Group (IFWG) and other stakeholders to further develop definitions, safeguards and additional protections for "biomass," "renewable biomass," and forest biomass. The Board further directed the Executive Officer to propose amendments to the LCFS regulation by December 2009, if appropriate.

V-11. Comment: ARB staff proposes modifications to section 95484(d) that would allow the Executive Officer to post on ARB's website detailed information regarding physical pathways in accordance with the California Public Records Act, and ARB regulations. The new subsection still does not specify how ARB will treat "trade secrets" contained within pathway information submitted to ARB by regulated parties. Thus, WSPA recommends that ARB staff modify this section to mention specifically that the confidentiality of trade secrets in pathway submissions will be protected from public disclosure pursuant to Govt. Code § 6254.7 and 17 CCR §§ 91000-91022. (WSPA5)

Response: We agree. The regulatory text in section 95484(d)(5) ("Evidence of Physical Pathway") was modified in the Second 15-Day Change Notice to read as follows:

(5) The Executive Officer shall post on the ARB's website at <http://www.arb.ca.gov/fuels/lcfs/lcfs.htm> the names and contact information for each regulated party and non-regulated party fuel producer that has obtained Executive Officer approval of its physical pathway demonstration; the transportation fuels and blendstocks covered by such Executive Officer approval; and details of the approved physical pathways disclosed in accordance with 17 CCR §§ 91000-91022 and the California Public Records Act (PRA) (Government Code section 6250 et seq.).

Title 17, CCR, sections 91000-91022 and the California Public Records Act set forth the requirements for the treatment of "trade secrets." Thus, with the regulatory text modified to read as shown above, the regulation now accomplishes the commenter's objective by requiring that details of approved physical pathways be disclosed "in accordance with" ARB's confidentiality regulations and the PRA statute.

V-12. Comment: WSPA is also concerned that confidential business data that may be included in Quarterly and Annual reporting is not included under proposed new subsection 95484(d)(5)) (which only relates to the posting of information related to demonstrations of physical pathways), and so will be unprotected from public disclosure. Therefore, WSPA recommends that ARB staff add additional language to the Reporting Requirements in section § 95484(c) specifically addressing ARB's treatment of confidential business information contained in Quarterly and Annual reports. (WSPA5)

Response: It cannot be overemphasized that the success of the LCFS is dependent, in large part, on its transparency and accountability. Achieving these objectives would be undermined by the lack of public disclosure of key information, including but not limited to, carbon intensity values and volumes of fuels subject to the LCFS requirements. While the ARB's confidentiality regulations and the Public Records Act will continue to apply to information submitted under the LCFS, those protections are not absolute and do not prohibit all disclosures of information submitted to ARB. For example, under some circumstances, the disclosure of information can be permissible under a "balancing" of the public's interest (i.e., in seeing the disclosed information) against the submitter's interest in keeping the information confidential. In this case, the lack of a specific reference to the confidentiality regulations and the Public Records Act for much of the information submitted under this program puts regulated parties and the public on notice that disclosure of such information may weigh towards the public's interest.

V-13. Comment: Page 31 – Section 95484 (c)(3)(A)(1) – Specific Quarterly Reporting Requirements:

WSPA supports the revision to the regulation whereby all product transfer documents should be available to ARB upon request only. However, we do not support the new language indicating that it must be provided to the E.O. within 10 days of a request. WSPA believes a much more reasonable time to produce all these documents is 30 days and asks staff to revise this requirement accordingly. (WSPA5)

Response: To discourage tampering with records used in enforcement actions and to ensure that noncompliant fuel transactions are tracked down as quickly as possible, it is important that records, when requested, should be provided expeditiously. Product transfer documents are required under the regulation to accompany each transaction of a fuel or blendstock in which the regulated party status is transferred from the transferor (e.g., seller) to the recipient (e.g., buyer). Because of this, both parties in such transactions should have the product transfer documents readily available, and a requirement to submit such documents within a 2 week (10 calendar day) timeframe should not be unduly burdensome or difficult.

V-14. Comment: Page 40 – Section 95484(d)(5) –
(5) The Executive Officer shall post on the ARB's website at <http://www.arb.ca.gov/fuels/lcfs/lcfs.htm>, the names and contact information for

each regulated party and non-regulated party fuel producer, ~~which~~ that has obtained Executive Officer approval of its physical pathway demonstration; ~~and~~ the transportation fuels and blend stocks covered by such Executive Officer approval; and details of the approved physical pathways disclosed in accordance with 17 CCR §§ 91000 – 91022 and the California Public Records Act (Government Code section 6250 et seq.).

WSPA is concerned with the addition of the requirement that details of the approved physical pathways shall be disclosed on ARB's website. This portion of the section is expanding the amount of information being disclosed. We have already indicated our concerns with the confidentiality protection of detailed information above and in previous comments. (WSPA5)

Response: As the language noted by the commenter plainly states, details of approved physical pathways would be disclosed only in accordance with applicable ARB confidentiality regulations and the Public Records Act. Generally, information identified as "trade secret" is protected from disclosure. However, the mere fact that information submitted to ARB may be confidential does not confer it with absolute protection against public disclosure. Under certain circumstances, even data identified as confidential or trade secret may be disclosed pursuant to the ARB confidentiality regulations and the Public Records Act. The language added to section 95484(d)(5) simply reflects current law, and whether submitted information is subject to disclosure depends on the circumstances and will therefore be determined on a case-by-case basis.

Section 95485

V-15. Comment: In reviewing Table 4 of Section 95485 (page 41 of the Modified Regulation Order, "LCFS Credits and Deficits") it appears that the energy density listed for denatured ethanol (80.53 MJ/gal) is incorrect. Based on information presented in the corn ethanol pathway document (http://www.arb.ca.gov/fuels/lcfs/022709lcfs_cornetoh.pdf), it is clear that the carbon intensity values for ethanol incorporated into the regulation (Table 6, page 48 of the Modified Regulation Order) are based on denatured ethanol, but the energy density value of 80.53 MJ/gal is based on non-denatured, anhydrous ethanol. This is confirmed by considering the lower heating values presented on page 67 of the corn ethanol pathway document cited above:

Anhydrous ethanol = 76,330 BTU/gal
Denatured ethanol = 77,254 BTU/gal

Using the conversion of 1055 J/BTU, the above values become:

Anhydrous ethanol = 80.53 MJ/gal
Denatured ethanol = 81.50 MJ/gal

Thus, Table 4 of the regulatory text needs to be revised to report the correct value for the energy density of denatured ethanol, 81.50 MJ/gal. ARB might also consider avoiding the use of “neat denatured ethanol” as the descriptor, as “denatured” implies that the ethanol is no longer “neat.” (WSPA5)

Response: Table 4 in section 95485(a)(1) has not been modified from the originally proposed regulatory text. Therefore, this comment falls outside the scope of the Second 15-Day Change Notice and requires no further response. We note that the commenter is correct in that the label for ethanol is incorrect, but the correct term instead should be “anhydrous ethanol.” Accordingly, the label was modified in Table 4 as a nonsubstantive correction.

V-16. Comment: Page 44 - Section 95485 (c) Credit Acquisition, Banking, Borrowing, and Trading. WSPA continues to be interested in developing the details of the credit trading program. We believe there continues to be significant gaps and issues with the way the regulation is currently worded and further clarity is needed. (WSPA5)

Response: Staff has initiated work on the credit trading provisions, and we anticipate proposing for the Board’s consideration regulatory language for section 95485(c) sometime in 2010, with the adopted provisions to go into effect before credits are to be traded starting after 1st Quarter, 2011. We look forward to working with interested stakeholders to develop those provisions.

Section 95486

V-17. Comment: Page 45. Section 95486. Determination of Carbon Intensity Values (a)(3)(a) Selection of Method. Section (3) has been added to this subsection. This new paragraph establishes that regulated parties are responsible for choosing the carbon intensity value for their fuel or blend stock from the Lookup Table, subject to review and possible modification after the fact by the Executive Officer. This proposal suffers from several serious flaws:

1. It does not encourage dialog between ARB and regulated parties to determine the most appropriate carbon intensity value based on process specifics.
2. It creates uncertainty by requiring regulated parties to self-determine their appropriate carbon intensity, subject to second-guessing by ARB at some unspecified later date.
3. It does not appear to protect recipients of the product from the consequences of carbon intensity changes made by ARB after the fact.

In place of the current proposal, ARB should establish provisions for registration of regulated parties. Producers are best positioned to determine the carbon intensity of the low carbon fuels they produce, but they should not be left to make such a determination in a vacuum. Producers will be required to register with

EPA under RFS2; similarly, ARB should require producers supplying biofuels to California to register their production facilities.

Registration should include the carbon intensity(ies) of the biofuel(s) produced at the production facility, and any disagreement between the proposed values and what ARB believes they should be should be resolved as part of this process. A listing of registered producers and their production facilities should be maintained on the ARB website and could be associated with the ARB carbon intensity look-up table. This would provide certainty in the establishment of both carbon intensity values and could also be a benefit to physical pathway demonstrations.

If ARB believes that, in addition to the registration process, it is necessary to have the ability to revise the carbon intensity value(s) assigned to a producer, it is essential that: 1) ARB has a defined, limited time period in which to make such changes; and 2) to the extent that the changes are retroactive, the consequences should be limited to the producer/importer in question and not to recipients of the producer/importer's product (e.g., a non-transferable deficit could be assigned to that producer).

Alternatively, ARB could achieve these results by explicitly stating in the regulatory language that changes in carbon intensity values will not be applied retroactively. (WSPA5)

Response: With respect to the Executive Officer being able to review and override a regulated party's selection of a carbon intensity value, this is addressed in response to Comment V-20. And with respect to the suggestion that fuel producers be required to register their carbon intensities and fuel pathways, this is addressed in response to Comment V-21.

With respect to the time period in which carbon intensity values may be changed and applied retroactively, a defined, limited time period in which to make such changes would unnecessarily hamper ARB's ability to implement the regulation. Under section 95484(c)(3), carbon intensity values are to be reported on a quarterly and annual basis. This means that the most likely times the Executive Officer may question a selected carbon intensity value is right after the quarterly and annual reporting. However, the Executive Officer may not become aware of relevant information that may affect a selected carbon intensity value until well after the quarterly and annual reporting have been conducted. For example, a USDA report that is relevant to the selection of a biofuel's pathway and carbon intensity value may be released at some point in the year well past the LCFS' fixed reporting dates. Thus, it would be inadvisable to fix a time period during which the Executive Officer may question a regulated party's choice of carbon intensity values.

With respect to the question of retroactively applying a change in carbon intensity value, we noted previously that the extent to which the Executive Officer may override a regulated party's choice is expected to be limited. To the extent that the Executive

Officer may actually change a selected carbon intensity value as described above, most such instances will be expected to apply prospectively. However, it is inadvisable to prohibit the Executive Officer from retroactively applying such a change in all cases, particularly in enforcement cases where misrepresentation, fraud, or other misconduct has been found. The appropriate remedies in such enforcement cases are best determined on a case-by-case basis, with consideration for the circumstances involved.

V-18. Comment: Pages 48 & 50 Section 95486. (b)(1) – Tables 6 and 7. WSPA notes the two tables still do not contain any HCICO pathways. There remains considerable uncertainty around the implementation of the HCICO provisions. We note our previous questions regarding the subject of HCICOs which have not yet been addressed:

- How will a refiner know if a new crude it decides to use is a high carbon intensity crude?
- How long will the use of and/or how much volume of a new crude need to be in order to necessitate the triggering of a carbon determination?
- Is a new crude considered high carbon intensity until demonstrated otherwise?
- Is the refiner using the crude responsible for the demonstration that the crude is not high carbon intensity?

In addition, we are unsure how the default value is developed and how a party determines which CI it should use. There has been little clarity regarding what is meant when we are told to choose the carbon intensity nearest to the pathway one is using, and how to go about pre-registering carbon intensities. (WSPA5)

Response: See response to Comment V-58. With regard to the volume of a new crude oil, the regulation does not specify a threshold that triggers a “carbon determination.” Under the calculations specified in section 95486(b)(2)(A)2.a., the regulated party has to account for all volumes of HCICO and non-HCICO-derived fuels in a calendar year.

With regard to which entity is responsible for demonstrating the a crude is or is not a high intensity crude, under section 95486(b)(2)(A)2. that entity is the regulated party since it is the regulated party that must calculate the deficits for CARBOB, gasoline, or diesel fuel, derived wholly or in part from crude oil subject to section 95486(b)(2)(A)2. (i.e., all other CARBOB, gasoline, or diesel fuel, including those derived from HCICO, not otherwise subject to section 95486(b)(2)(A)1.).

V-19. Comment: Page 54 – Section 95486 (b)(2)(A)(2)(a) Deficit Calculation When HCICO Is Used. Overall, WSPA wants to highlight that this section is very confusing and needs further accelerated regulatory work. We do not know what criteria or process ARB is using to determine what the carbon intensities are of various crude oils around the world and how we calculate whether the crude meets/does not meet the 15 gm limit or trigger point.

Is ARB going to produce a list of crudes separate from the regulation with carbon intensity values for various crude types, locations, etc.? Will ARB be producing a list of crude oils that the agency considers to not be HCICOs? Will ARB be grouping HCICOs into a basket which will get inserted into the Lookup Table? (WSPA5)

Response: See responses to Comments V-18 and V-58.

V-20. Comment: BIO supports California's efforts to reduce the carbon intensity of transportation fuels. However, BIO urges the ARB Board, and the Executive Officer of the Board, to employ sound science in the determination of these values. As cited in Section 95486 (a)(3) of the modified regulation order, "If the Executive Officer has reason to believe that the regulated party's choice is not the value that most closely corresponds to its fuel or blendstock, the Executive Officer shall choose a carbon intensity value...which the Executive Officer determines is the one that most closely corresponds to the pathway for that fuel or blendstock." If the Executive Officer chooses to amend the carbon intensity value determined by a regulated party, and there is no Board hearing required prior to the Executive Officer's decision, BIO believes that a mechanism for appeals to that decision must also be included in the rulemaking. (BIO2)

Response: There is no legal requirement under State law for the LCFS regulation to allow a regulated party to appeal an Executive Officer's decision. In addition to the lack of a statutory requirement, there are other reasons why a formal appeals provision in the regulatory text is unnecessary. First, the Executive Officer's decision to select a carbon intensity value that more closely corresponds to the regulated party's fuel pathway will be explained in writing. This will allow the regulated party to see the Executive Officer's rationale and how the Executive Officer reached his/her decision.

More importantly, in reaching a decision that results in a higher value than that chosen by the regulated party, the Executive Officer is allowed and expected to consider any information submitted by the regulated party in support of its choice of carbon intensity value. Thus, a dialogue is already built into the regulation for the regulated party and the Executive Officer to discuss differences of opinion as to which carbon intensity value is most appropriate. The regulated party will have ample opportunity to provide documentation in support of its choice of carbon intensity value.

Further, the Executive Officer's decision is not necessarily permanent; the chosen carbon intensity may change in the future if the regulated party's circumstances change; additional information becomes available after the Executive Officer's decision; a new, more appropriate carbon intensity value is added to the Lookup Table; or an existing carbon intensity value is modified subsequently and the modified value is more appropriate for the regulated party's fuel pathway.

It should be noted that the originally proposed regulatory text was not clear as to how and, more importantly, who would make the choice of which value in the Lookup Table to apply to a particular fuel pathway. Early versions of the regulation had the selection being conducted solely by the Executive Officer, with no mechanism for appealing that selection. By contrast, the regulation as approved with modifications at least provides the regulated party with the first opportunity to make that selection. In the vast majority of cases, it is expected that the regulated party's selection will be deemed appropriate and no further action is required. However, it became clear that the Executive Officer needed to reserve the right to question a regulated party's selection and, with a sound rationale and input from the regulated party, be able to override the regulated party's initial choice if a more appropriate carbon intensity value is shown in the Lookup Table.

Other Regulatory

V-21. Comment: While there is a clear requirement for regulated parties to report in full compliance effective 1/1/2010 there is, however, no requirement for fuel (biofuel) producers to register and no clear requirement for them to report pathways and carbon intensities effective 1/1/2010. In fact, one might imply from the credit rule section that carbon intensity and pathway data are not needed until 1/1/2011. (WSPA5)

Response: This issue was addressed in response to Comment IV-183 for the First 15-Day Change Notice. In short, to the extent biofuel producers supply transportation fuel or blendstock to California, they were already required under the originally proposed text to demonstrate their fuels' physical pathways if they wanted to receive credit for such fuels under the LCFS program. Similarly, under the originally proposed regulatory text the biofuel providers would already be "required" to supply carbon intensity information, either directly to ARB as regulated parties or indirectly via the producer or importer to which they supply their biofuels.

To the extent that such biofuel producers do not supply fuel directly to California and have no other contacts with California, there likely would be jurisdictional issues with requiring them to register their facilities and carbon intensities. Thus, to encourage the submittal of LCFS-related information from such facilities, we modified the regulatory text in the Second 15-Day Change Notice to allow biofuel producers that do not otherwise qualify as regulated parties to demonstrate a physical pathway to California. The intent of this modification is to provide the fuel producers who purchase such biofuels and bring them into California a way by which they can cite to and rely on those approved physical pathway demonstrations submitted by non-regulated party biofuel producers.

V-22. Comment: The regulation creates a need for carbon intensity and pathway data by regulated parties, but not a requirement for biofuels producers to provide them. This conflict also makes it unreasonable to expect fuel producers who purchase biofuels to comply in the first quarter under these conditions. (WSPA5)

Response: It is neither necessary nor advisable to make all biofuel producers, particularly those with no direct personal contacts with the State, to register and provide a fuel pathway. As noted above, a biofuel producer that is also a regulated party is required to meet the pathway demonstration and other reporting requirements the same as any other regulated party. A biofuel producer that is not a regulated party (i.e., it does not produce in or import into California a covered transportation fuel or blendstock) is allowed, but is not required, to provide a demonstration of physical pathway. This change was described in the Second 15-Day Change Notice. It seems axiomatic that a biofuel producer that fails or refuses to provide carbon intensity and pathway data to its customers would be at an economic and competitive disadvantage compared to similar biofuel producers that are willing to provide such information for its customers. Thus, it seems unlikely that the issue raised by the commenter will result in a substantial burden to regulated parties under the LCFS.

V-23. Comment: It is only three months until the first compliance date and we still do not have a final rule. We understand that the final rule is not expected to be available until very late 2009 which will provide less than one month (probably days) to comply with a very complex and groundbreaking rule that has been 3 years in development. That schedule is unrealistic; it does not allow enough time to develop compliance plans or automated systems to gather data from our own electronic data management systems for 1Q10 reporting. It is unreasonable to expect regulated parties to comply in the first quarter under these conditions. (WSPA5)

Response: The effective date for the reporting requirements and demonstration of physical pathways (Jan. 1, 2010) was not modified in the Second 15-Day Change Notice. Therefore, this comment falls outside the scope of the Second 15-Day Change Notice and requires no further response.

V-24. Comment: We want to re-emphasize our previous comments and concerns about the promulgation timeline and allowance for due process in rulemaking while providing regulated parties an adequate timeline for compliance. Our concern is heightened in this aspect by the fact that there are less than three months until the regulation goes into effect – yet there remains no final rule that we, or other parties in the biofuels supply chain that we are dependent upon, may use to coordinate a responsible compliance response. Additional facts are that ARB is lacking in providing the necessary data and tools that we and others will be required to use to comply (most notably: look-up table values for high carbon intensity crude oil (HCICO); look-up table values for soy-based renewable diesel and biodiesel; and development/deployment of the mandatory electronic “Compliance Reporting Tool”). (CONOCO3)

Response: The effective date for the reporting requirements and demonstration of physical pathways (Jan. 1, 2010) was not modified in the Second 15-Day Change Notice. Similarly, there were no changes in the compliance schedules set forth in section 95482 (starting Jan. 1, 2011). Therefore, the portion of the comment dealing

with the promulgation timeline falls outside the scope of the Second 15-Day Change Notice and requires no further response.

With respect to completion of carbon intensities for soy-based renewable diesel and biodiesel, ARB intends to adopt carbon intensity values for these pathways as part of this rulemaking before March 4, 2010, as discussed in Section I.A. of this FSOR.

Regarding a carbon intensity for HCICO, as stated in Section 95486(b)(2)(A)2.a.ii.I-III. of the regulation, it is the regulated party's obligation to determine the carbon intensity of an HCICO-derived petroleum product, which would then be subject to the Executive Officer's review and approval. See response to Comment V-58. As regulated parties obtain approval for their HCICO pathways, those pathways will be incorporated into the Lookup Tables through formal rulemakings.

With respect to the development/deployment of the mandatory electronic "Compliance Reporting Tool" (now called the "LCFS Reporting Tool" or "RT"), this form is under development and should be available by March, 2010. The RT itself is not part of the regulation but is to be made available by ARB for use by the regulated parties. As noted this will be deployed by March, 2010.

V-25. Comment: This issue of developing engine technology, vehicles and fuels as a "system" was not addressed in the LCFS. Caterpillar believes this is a major issue due to the uncertainties involved. There are already some known technical issues with some renewable fuels, such as high paraffins, low and high aromatic levels, lower heating values, resultant ash build-up and other technical issues, which can negatively affect engine performance, machine design, maintenance intervals and/or emissions. And, since these various renewable fuels have not been fully validated in today's and tomorrow's engine technologies beyond the B5 fatty acid methyl ester bio-diesel levels, let alone levels including other fuel, there may be unknown consequences and/or unintended, consequences of different and/or higher blends. (CATERPILLAR)

Response: Engine performance concerns were discussed in response to Comments V-63 through V-70 below. As noted in response to Comment V-63, the LCFS does not set fuel specifications. If and when ARB adopts individual fuel specifications, these performance issues will be addressed at that time. For example, when the Board considers specifications for biodiesel and renewable diesel (tentatively scheduled for mid-2010), the potential impacts of such fuels on engines will be considered.

V-26. Comment: Mobile products [such as biodiesel and other renewable biofuels] are transient and often serve end users across multiple jurisdictional boundaries. Differentiated fuel specifications and standards negatively affect product utilization, economic value, and product reliability. Specifications and standards that are adopted need to be clear, consistent, and universally enforced. We would recommend that ARB engage with the EPA – through its RFS2 Notice for

Proposed Rule Making (NPRM) efforts – to ensure that consistency nationwide. (CATERPILLAR)

Response: ARB is already engaged with U.S. EPA and has commented on the RFS2 rulemaking. We anticipate continuing that dialogue. As noted on page ES-5 of the Staff Report, the LCFS regulation is designed to complement the federal RFS2 program. Thus, it is in both agencies' interest to be as engaged as possible and to ensure the applicability of programs like the LCFS across the nation and even internationally.

B. Land Use Change and Other Indirect Effects

V-27. Comment: The new pathways included in the Executive Officer's September 23 notice require peer review under the Health & Safety Code, for the same reasons as those stated in Growth Energy's prior comments. See Health & Safety Code § 57004 and Aug. 19 Growth Energy Comments at 12. Just as the carbon intensity values in the ARB Lookup Table dating from March 2009 should have received full external peer review, those that have been added by the Executive Officer should have been subjected to peer review. Clearly many other factors are interacting with land-use decisions and global markets, as shown by the research at ORNL reviewed above. An expert who is in a far better position to opine on this issue than many participants in this rulemaking (Prof. Tyner) has now released results from GTAP modeling that demonstrate that the GTAP results on which the Board has previously relied are seriously in error. After the necessary external peer review has occurred, its results should be made available for public review and comment before the Board takes any action on the proposed additions to the Lookup Table. (GE6)

Response: The Second 15-Day Notice issued September 23rd, 2009, identified slightly modified versions of six pathway supporting documents that ARB was adding to the rulemaking record. An independent peer review of these modifications to the pathways is not required under state law because these are technical results of a scientific analysis that was peer reviewed pursuant to H&S Code Section 57004.

C. Lifecycle Analysis

Sugarcane

V-28. Comment: The Brazilian Sugarcane Industry Association (UNICA) submits the attached comment letter on the U.S. Environmental Protection Agency's proposed rulemaking for the Renewable Fuel Standard program (the "RFS2 Proposed Rule"). We believe the topics covered in UNICA's comments on the RFS2, which include recommendations related to direct lifecycle assessment and indirect land use change calculations are directly relevant to the implementation of the LCFS. Based on the conservative results of a Brazil-specific, partial-equilibrium land use model for the "indirect" emissions and the required emission credits from bioelectricity, the revised results for the sugarcane ethanol pathway

should be revised to 82 percent and 73 percent for 100 year with a 2 percent discount rate and 30 years with no discount rate, respectively. (UNICA3)

Response: We have provided credit for electricity produced and exported in our new subpathway for ethanol from Brazilian sugarcane made available for comment with the First 15-Day Change Notice. We will continue to consider new data as it is developed, which could result in new carbon intensity values using Method 2A. The Expert Workgroup will evaluate refining and improving land use change, including indirect effects. This may also result in evaluating changes to the carbon intensity for ethanol from sugarcane.

V-29. Comment: The Executive Officer's description of his most recent revisions in the cane ethanol pathway analysis as "minor" deserves attention. As explained in an accompanying declaration, a comparison of the prior and now-revised pathway analyses shows many changes. Those changes vary considerably from value to value, and the specific reason for each change is not documented. See Supplemental Declaration of James Michael Lyons ("Lyons Supp. Decl.") ~ 3. The public has not been given sufficient information in the rulemaking file or in the Executive Officer's publications to understand adequately the basis for the original numerical values in the earlier ARB cane ethanol analysis, nor in the September 23 revised documentation. This does not substantially comply with the APA. If the Executive Officer does not take the primary step that Growth Energy has in the past requested and continues to request – which is to return the proposed regulation to the Board for further consideration – Growth Energy asks that the Executive Officer place all the necessary information in the rulemaking file, provide public notice of his action, and then permit adequate time for public comment and review before any further or final consideration of the cane ethanol pathways occurs. (GE6)

Response: The initial pathway documents for producing ethanol from sugarcane using average production processes were made available for a 30-day informal review, and a 45-day formal comment period after issuance of the hearing notice. Revisions expanding the documents to include as well Brazilian sugarcane ethanol with mechanized harvesting and electricity co-product credit, and with electricity co-product credit, were made available for the 30-day comment period in July-August 2009, with minor additional modifications made available for the second 15-day comment period. We have received and responded to a number of comments on general aspects and details of the calculations. Changes have been made to some of the documents as a result. These include comments from Growth Energy on the Brazilian sugarcane pathway and from RFA on the corn ethanol pathways. After carefully considering Growth Energy's comments, we are satisfied that ARB has complied with California administrative laws with respect to the sugarcane ethanol pathways.

V-30. Comment: Information that has become available since August 19 makes it clear that the ARB's version of the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation ("GREET") model, called "CA-GREET," does

not properly account for transport of Brazilian cane ethanol to California, nor for the energy required to dehydrate the hydrous ethanol produced in Brazil for use in the California market. See Lyons Supp. Decl. ~ 5-8. Those deficiencies do not comport substantially with ARB's statutory obligation to use the "best available economic and scientific information." See Health & Safety Code § 38652(e); Aug. 19 Growth Energy Comments at 20. They also constitute a substantial defect in the environmental assessment required by CEQA, which should be corrected in the resubmission of the matter to the Board required by CEQA and ARB's implementing regulations. See *id.* at 29-30. These omissions are certainly not minor: correction of the error related to energy usage in dehydration increases the carbon intensity value for the "Baseline Brazilian Ethanol" pathway in the September 23, 2009 version of the ARB Lookup Table by about 20 percent, and the percentage increases for the other two ARB Brazilian Ethanol pathways are even larger. See Lyons Supp. Decl. ~ 7. (GE6)

Response: The commenter appears to miscomprehend the sugarcane ethanol pathway that was modified in Table 6 as part of the Second 15-Day Change Notice. This pathway was correctly presented by ARB (except for the minor error that was corrected as described in the Second 15-Day Change Notice). The pathway in Table 6 reflects a pathway by which *anhydrous* ethanol produced from Brazilian sugarcane is transported to California (i.e., the ethanol was dehydrated in Brazil). By contrast, the pathway described by the commenter represents a completely different pathway, which involves the transport of hydrous ethanol from Brazil to the Caribbean, where it is dehydrated prior to being transported as anhydrous ethanol to California. Thus, the commenter's point, to the extent it may be valid, would apply if ARB had adopted a pathway representing the transport of hydrous sugarcane ethanol from Brazil. However, since no such pathway was established in Table 6, this comment falls outside the scope of the Second 15-Day Change Notice and requires no further response.

It should be noted that ARB staff is in the process of working with the U.S. EPA and with companies involved in the dehydration process to collect data for possible use in establishing a modified sugarcane ethanol pathway under Method 2A (section 95486(c)). However, until the pathway as described by the commenter is incorporated in Table 6 through a future rulemaking, regulated parties for sugarcane ethanol entering California after dehydration in the Caribbean will not be allowed to use the carbon intensities currently shown in the adopted regulation's Lookup Table for Brazilian sugarcane ethanol.

The Expert Workgroup to be established under Resolution 09-31 may examine these and related issues. There are also two mandatory program reviews by 2012 and 2015 (section 95489) at which time this could be reviewed.

Also see the responses to Comments V-48 through V-51.

V-31. Comment: The September 23 notice does not deal adequately with Growth Energy's earlier comments on the carbon intensity values assigned to the cane

ethanol pathways. While some adjustments have been made to the mechanized harvesting pathway apparently to take partial (but not complete) account of equipment emissions, see Lyons Supp. Decl. ~ 9, Growth Energy's earlier questions concerning the Executive Officer's assumption that all surplus energy will replace natural gas usage have not been addressed. See *id.* ~ 10. This creates two distinct problems under the APA and CEQA. The first is that ARB is committing a substantive, and substantial, error in its emissions analysis. The second defect is procedural. Even if the Executive Officer believes that his assumption about the displacement of natural-gas-based energy is reasonable, the public is entitled to comment on his basis for that conclusion, now that Growth Energy has questioned the basis for the Executive Officer's assumption. There is also now additional evidence, which Growth Energy could not obtain in the limited time permitted for comment on the Executive Officer's July 20 notice, that the Executive Officer's assumption concerning displaced energy is erroneous. See *id.* ~ 11. Here as well, under his own view of his delegated powers, the Executive Officer has a duty under the APA, CEQA and the Board's CEQA regulations to explain the basis for his assumption and to permit public comment before any final action or determination is made with respect to the cane ethanol pathways. (GE6)

Response: The amount of surplus electricity has been modeled as marginal electricity that would have to be generated if this surplus was not available. The analysis therefore accounted for the exported electricity as being marginal from natural gas sources. The producer has to provide data to support the exported electricity to be able to use the carbon intensity for this particular sugarcane ethanol pathway depicted in the Lookup Table. There have been no violations of the APA or CEQA.

V-32. Comment: There are still obvious errors in the September 23, 2009 version. For example, summation of the values presented in either column of Table M does not yield the values for "Total GHG Emission" presented in Table M. (GE6)

Response: The sum of the table M is correct as detailed in table 5.04. However, the individual values within the column were incorrectly transferred. Because the errors were typographical in nature, the errors were corrected as nonsubstantive changes to the pathway document for sugarcane ethanol.

V-33. Comment: The ARB staff's updated analysis still fails to address a number of flawed assumptions that led to an underestimation of the carbon intensity values for Brazilian Ethanol. An important example of this can be seen in ARB's assessment of GHG emissions due to transport of Brazilian ethanol to the California. As stated on page 11 of the September 23, 2009 version of the Brazilian Ethanol Pathway document, ARB assumes that "[a] significant fraction of ethanol imported into the U.S. is processed as hydrated ethanol (5 percent water) in the Caribbean where denaturant is also added. This delivery mode is not modeled in CA-GREET so the pathway based on delivering anhydrous ethanol to California is shown here." This CA-GREET modeled pathway is used

in the determination of the carbon intensity values for Brazilian ethanol. ARB's use of the CA-GREET pathway based on delivery of anhydrous ethanol, instead of a Life-Cycle Analysis (LCA) that accurately reflects ARB's understanding of the transport and processing of hydrated ethanol from Brazil in the Caribbean, leads to an underestimation of the carbon intensity value for Brazilian ethanol. Hydrous ethanol has a somewhat higher density and somewhat lower energy content than anhydrous ethanol. The difference in density is approximately 2 percent the difference in energy content on an equivalent volume basis is about 3 percent. Proper accounting for those factors, particularly during transport of ethanol inside Brazil and by tanker from Brazil, will increase the GHG emission estimates for Brazilian ethanol. (GE6)

Response: Caribbean Basin Initiative (CBI) has commented this subject in this 15-day comment period that the carbon intensity should be lower if sugarcane ethanol is dehydrated in Trinidad before shipping to U.S and California. Staff is in process working with U.S EPA and companies involved in dehydration to collect data for the modified pathway under Method 2A. Transport of ethanol inside Brazil and from Brazil has been accounted for in the pathway. Also see the responses to Comments V-48 through V-51.

V-34. Comment: Energy is required to dehydrate cane ethanol to the anhydrous form used in the U.S. There is no indication that the GHG emissions associated with the production of the energy required for this process have been accounted for in CA-GREET. Molecular sieve technology is reported to have an energy requirement of approximately 6,000 btu per gallon of hydrous ethanol that is dehydrated. Assuming that this process energy requirement is met using steam from an 80 percent efficient Diesel fueled industrial boiler (which appears to be a reasonable assumption based on comments submitted to U.S. EPA by Caribbean Basin Ethanol Producers Group), and using the CA-GREET-based GHG emission factor for such a boiler of 78,298 gCO₂eq emissions per million btu of energy input and a value of 80.53 MJ/gal for anhydrous ethanol, the GHG emissions associated with dehydration amount to approximately 7.29 gCO₂eq/MJ. Addition of this value to the ARB carbon intensity value for the Baseline Brazilian Ethanol pathway in the September 23, 2009 version increases the carbon intensity value by about 20 percent to 34.7 gCO₂eq/MJ; the percentage increases for the other two ARB Brazilian Ethanol pathways are even larger. (GE6)

Response: The Brazilian sugarcane ethanol pathway does not include dehydration in the Caribbean. We are in the process of collecting data and information to complete an analysis of ethanol dehydration and will establish a new pathway when this is completed. Also see the responses to Comments V-48 through V-51.

V-35. Comment: CA-GREET assumes that the 150,000 DWT tankers will be used for Brazilian ethanol shipment. Tankers of this size have volumes 50 to 70 percent greater than the largest tankers that can pass through the Panama Canal (so-

called “Panamax” tankers). Given this, Brazilian ethanol processed in the Caribbean would likely need to be transported in smaller and likely less energy efficient tankers through the Panama canal to California, with the result being greater GHG emissions than is estimated by CA-GREET. (GE6)

Response: CA-GREET assumes all ocean tanker size to transport ethanol is 150,000 DWT. To support the different sizes of tankers used, staff would need to have the data from the shipping company. The Expert Workgroup will address this issue. Also see the responses to Comments V-48 through V-51.

V-36. Comment: This revised value does not accurately reflect the GHG emissions impacts associated with additional diesel fuel use and process energy required for mechanized harvesting. These emissions are ignored by the ARB staff in arriving at the value of the carbon intensity credit for mechanized harvesting. Although there is no single approach to mechanized harvesting, factors related to increased Diesel fuel use and additional energy requirements for cane and trash processing must be accounted for in assessing the GHG emissions associated with Brazilian sugarcane ethanol. This is acknowledged by Wang et al., who note that there could be differences in energy use and therefore GHG emissions between the two harvesting methods that are not accounted for in GREET or CA-GREET. (GE6)

Response: See response to Comment IV-68.

V-37. Comment: In contrast to the carbon intensity credit for mechanized harvesting, the Executive Officer has not revised the carbon intensity credit provided to Brazilian ethanol produced in plants that generate surplus electricity. The value of that credit continues to be based on the assumption that all of the surplus electricity generated from ethanol production displaces natural gas based electricity generation. The source of the data used is reported to be “M. Wang, et al.: WTW Energy Used and GHG Emissions of Brazilian Sugarcane Ethanol – July 2007.” The following quotation from this reference highlights the speculative nature of the value of electricity co-product credit, which was also included in the 2008 publication by Wang et al.: “We assumed in our analysis that the exported electricity from sugarcane ethanol plants will displace electricity generated in natural gas electric power plants, which are believed to be the marginal electric power plants in Brazil. On the other hand, if the exported electricity displaces the average electricity in Brazil (83 percent of which is from hydro-power), GHG emission benefits of sugarcane ethanol are reduced by up to 8 percentage points.” (GE6)

Response: See response to Comment IV-68.

V-38. Comment: In addition, the assumption that all surplus electricity from ethanol production will displace natural gas based generation is not supported by other sources, including the U.S. Department of Energy. These sources indicate that

rather than relying solely on increased natural gas based electricity generation capacity, Brazil plans to rely mainly on expanded hydro-power and nuclear power generating capacity. Obviously, to the extent that surplus electricity from ethanol production displaces other sources that do not have associated GHG emissions, there should be no GHG emission reduction credit provided to sugarcane ethanol. (GE6)

Response: Staff disagrees. The amount of surplus electricity should be credited either to the grid or for use in the plant which can displace electricity that otherwise would have been used.

Corn Ethanol

V-39. Comment: The Executive Officer's obligations and those of the Board to apply the best available science to the LCFS rulemaking require the Executive Officer to return the proposed regulation to ARB to consider this important new information and analysis. If the Executive Officer does not agree, he should explain fully why he disagrees, before he takes final action on the proposed regulation, and he should invite comment on his analysis. If, contrary to Growth Energy's request, the Executive Officer decides instead to take final action without permitting further comment, then his mandate to use the best available scientific and economic information and to minimize leakage certainly would require him to amend the Lookup Table to reduce the 30 g/MJ carbon intensity value by at least 30 percent, based on Prof. Tyner's latest work. Growth Energy also believes that if the Executive Officer pursues final action now, he would also be required to select a 9 g/MJ carbon intensity value to replace the 30 g/MJ value in the currently proposed Lookup Table, as proposed by RFA, in light of the work by AIR and Dr. Shurson. If the Executive Officer does not make either of these adjustments, he must explain fully his reasons for not doing so. (GE6)

Response: In Resolution 09-31, Board found that the regulation as approved was based on the best available science; this was reaffirmed with respect to the final regulation in Executive Order 09-31. There is no legal requirement for ARB to address new material submitted after the close of the comment periods for submittal of such information.

V-40. Comment: By "averaging" fuel pathways and GHG emissions from different processes used to develop, process and transport the same type of fuel (e.g., "Corn Ethanol Midwest; Wet Mill, 100 percent NG"), a fuel provider whose emissions are greater than the average will benefit from the assumptions. A producer of corn ethanol could benefit from the averaging of emissions and processes having no cause to challenge the assumption in their favor. Whereas fuel providers with less emissions than the average can challenge the assumptions under the 2B option and the net effect is worse than average. A provider of Brazilian sugarcane ethanol could use mechanized harvesting and benefit from that fuel pathway's assumptions, but in actuality only use

mechanized harvesting for 10 percent of the crop and escape verification and enforcement protocols due to California's lack of international jurisdiction. Moreover, the claimed emissions reductions would not be "real" as legally required. (MELVER2)

Response: It would be impractical to develop pathways for every fuel production facility. Most of the pathways ARB has developed use average values for pathways using specific processes, feedstocks, and energy types used. We recognize that the development of new pathways may affect the overall average carbon intensities and we will monitor the affects of the new pathways. If necessary, we will make changes to the original carbon intensity values. In the case of two similar pathways, fuel producers must select the higher carbon intensity if they don't qualify for the lower carbon intensity. Staff will consider for future action a proposal that might qualify or demonstrate a partial co-product credit (e.g., mechanical harvesting, or partial wet DGS).

LNG

V-41. Comment: We note that the California-modified GREET model pathway for natural gas from remote sources was set to double-count process emissions under both "Processing" and "Overseas Liquefaction" (see e.g., page 5 of the September 23, 2009 v.2 document) Prior Sempra Energy comments provided information showing that processing is included within the liquefaction plant emissions at overseas facilities. (SEMPRA5)

Response: The pathway assumes that natural gas extracted from a gas field need to be "scrubbed" prior entering to LNG plant by removing water, CO₂, and others to prevent freezing under low temperature. These contaminants must meet the specifications for LNG. This activity (called NG processing) needs energy and generates GHG. After processing, the clean NG can now flow into the LNG plant for liquefaction process.

V-42. Comment: We also note that the assumed transportation distance of over 8,000 was unrealistic and that a distance of 5,000-6,000 miles is more likely. (SEMPRA5)

Response: Staff considers the distance from South East Asia (Indonesia) to Baja (Mexico) as the main supply route in the NG to LNG pathway document, total distance 7,067 nautical miles or 8,127 miles. If industry wishes to establish a modified pathway using Indonesia and Sakhalin (Russia) as the LNG origin, they can modify the current pathway under Method 2A.

V-43. Comment: The result is that the values reflected in Table 6 for imported LNG are inaccurate estimates. Values for overseas LNG are overstated by at least 4.0 gCO₂e/MJ. We have not yet seen an explanation of why staff has chosen not to accept these comments, if that is the case. Sempra Energy requests that the

Look Up Table 6 be changed to provide a more accurate carbon intensity for imported LNG. (SEMPRA5)

Response: Staff evaluated the information provided by Sempra and was unable to verify the information provided or its applicability to the LNG pathways set forth in Tables 6 and 7. Therefore, no changes have made to Table 6 and 7 in response to this comment. Pursuant to the Board's direction in Resolution 09-31, staff will continue to work with interested stakeholders to identify and develop additional LNG pathways for possible incorporation into the Lookup Tables in future rulemakings. The information presented by Sempra may serve as the basis for either a modified LNG pathway submittal under Method 2A or a new LNG pathway submittal under Method 2B (see section 95486(c) and (d)). A proposal for a modified or new LNG pathway in either case would be considered in a formal rulemaking process, as provided in section 95486(f).

Lookup Tables

V-44. Comment: POET is particularly concerned about the combined impact of the new proposed pathways and the Executive Officer's proposed elimination of any time limit on the review and approval process for alternative carbon intensity values under "Method 2" in proposed section 95486. The lack of any time limit on the approval process for Method 2 is exacerbated by the vague criteria and procedures for use in Method 2. When combined with all the additional pathways included in September round of proposed modifications to the Lookup Table in the Executive Officer's earlier post-hearing revisions, the elimination of any time limit for action on further adjustments using Method 2 would make POET noncompetitive as an ethanol supplier for the California market. (POET3)

Response: The commenter apparently misunderstands the Method 2A and 2B process in section 95486 as adopted. While the regulation sets forth the criteria under which a regulated party may propose revised carbon intensity values for modifications to pathways or new pathways, the final action on the proposed revised carbon intensity values will be taken by ARB in a noticed rulemaking under the APA (see section 95486(f)). The APA provides specific timeframes for conducting the formal rulemaking.

V-45. Comment: Table 6 on pages 48-49 of the Modified Proposed Regulation Order gives carbon intensity values for corn ethanol that would lead some to believe some forms of it are marginally superior to gasoline. By contrast, the selfsame table gives carbon values for electricity that are in excess of that for standard gasoline. By contrast, Table 5 on page 44 gives an Energy Economy Ratio for electricity that is thrice that for all forms of ethanol. Table 6 tends to favor some forms of corn ethanol over electricity. Table 5 tends to favor electricity over all forms of ethanol. Thus, there is a conflict of incentivisation between Tables 5 and 6. (ALEX3)

Response: Table 5 and 6 relate to two different aspects of a fuel's overall carbon intensity: energy efficiency and GHG emissions. Table 5 compares the efficiency of

vehicles to convert the various fuels into useful energy using a metric called “EER” for the comparison. The EER is the energy efficiency ratio, which is the ratio of miles driven per unit energy of a given fuel to the miles driven per unit energy of gasoline. To illustrate, Table 5 shows the EER of electric vehicles compared to the EER of gasoline vehicles (gasoline is assigned a value of 1.0). Based on the best available scientific information, the EER for electric vehicles is 3.0; in other words, if an electric vehicle and gasoline vehicle were fueled with the same gasoline gallon equivalent (gge) units of fuel, the electric vehicle would go 3 times as far as a gasoline vehicle.

Unlike Table 5, Table 6 compares the carbon intensity of the various fuels used in gasoline vehicles and vehicles substituting for gasoline vehicles. This table shows the GHG emissions of gCO₂/MJ of the full lifecycle of fuels from well to wheel (WTW). Table 6 (and its counterpart Table 7 for diesel and diesel substitutes) can be used to compare the fuel lifecycle carbon intensities of the various fuels. But for purposes of calculating credits and deficits for annual credit balancing requirement, neither Table 6 nor Table 7 can be used alone because they do not reflect the relative efficiencies of the vehicles in which the various fuels are intended to be used. Thus, in order to do the credit balancing calculation, an “adjusted” carbon intensity is needed, which combines both the fuel lifecycle carbon intensity and the EER value.

As stated in Appendix C of the Staff Report (at C-6), the EER can be used as a factor to adjust the WTW carbon intensity produced from lifecycle emissions of a fuel. This can be done by taking the WTW carbon intensity from Table 6 for a given fuel and dividing it by the EER for that fuel and application (light-duty/medium-duty vs. heavy-duty vehicle). For electricity, dividing the WTW carbon intensity in Table 6 for electricity by the EER in Table 5 yields an adjusted carbon intensity of electric cars of $(104.71 \text{ g/MJ}) / (3.0) = 34.9 \text{ g/MJ}$. Thus, although it may appear on Table 6 that some forms of ethanol have lower CI than electricity, once adjusted for efficiency, electric vehicles actually have lower overall carbon intensity than corn ethanol.

V-46. Comment: Interestingly, the carbon intensity values given for electricity in Table 6 do not seem reflective of the carbon intensity of hydro-power. (ALEX3)

Response: The California Electricity Portfolio includes the power generation from hydro-power, as provided in California Energy Commission in 2005, the hydro-power is 17.9 percent.

Additional Pathways

V-47. Comment: In addition, we understand that to be officially accorded a carbon-footprint reduction for the LCFS, Cobalt's fuel will be subjected to the California-Modified GREET Pathway for Transportation Fuels. We have completed our own lifecycle analysis, based on GREET but supplemented by specific analysis of our process where GREET data are lacking or inapplicable, and would be pleased to share this analysis with the ARB staff. We are aware of the Argonne National Lab corn-to-butanol GREET analysis; however, the differences

conferred by the two processes indicated to us that we should generate our own pathway model. We look forward to engaging with ARB staff as we move toward the development of a fuel pathway for biobutanol from lignocellulosic feedstocks. We are confident that Cobalt's proprietary technologies will make possible a new generation of cost-effective and domestically-produced biofuels that will play a significant role in achieving the Low Carbon Fuel Standard and help maintain California as the hub of green technology innovation. (COBALT)

Response: Method 2A/2B would be more appropriate for generating a new pathway that has not been established by ARB in the Lookup Table. Staff advises that the data should be provided to ARB for evaluation. The draft guidance for process of establishing a new fuel pathway is provided on the LCSF website.

Dehydration of Brazilian Sugarcane Ethanol

V-48. Comment: More specifically, this letter focuses on a proposed pathway utilizing natural gas to dehydrate ethanol in the Caribbean which originates from Brazilian sugar mills that are linked to electric co-product generation capability. (CANOPY)

Comment: First, instead of dehydrating the hydrous ethanol at the mill, the hydrous ethanol is transported to a CBI eligible location and dehydrated. The manufacturing process for anhydrous ethanol, which is approximately 198 proof or 99 percent alcohol by volume, generally consists of five functions: 1) feedstock preparation; 2) fermentation; 3) distillation; 4) drying (dehydration); and 5) storage. The dehydration step is necessary because ethanol can only be distilled to approximately 190 proof, or 95 percent alcohol by volume. This is referred to as hydrous ethanol. Second, instead of shipping the ethanol directly from Brazil to the U.S., the ethanol is shipped to an ethanol dehydration plant in the Caribbean, dehydrated, and then shipped to the U.S. And third, under the CBI, hydrous ethanol, dehydrated and transformed into anhydrous ethanol in a CBI eligible country is treated as if it had been produced in that country and is not subject to these tariffs. The total amount of CBI dehydrated ethanol allowed to enter the U.S. duty free annually is seven percent of the U.S.'s previous years' consumption of ethanol. (CANOPY)

Response: ARB staff will work with U.S. EPA and Canopy Inc. to collect data for this modified pathway.

V-49. Comment: Since CBI dehydration plants will be the most economically efficient pathways for sugarcane ethanol from Brazil to reach California, we urge ARB to include pathways under Method 1 (carbon intensity look up table). Failing to do so could create significant confusion since direct imports are economically disadvantaged and impractical. By analyzing the differences in the direct Brazil to U.S. pathway outlined in the September 23, 2009 version of the pathway document for Brazilian sugarcane ethanol ("CARB923") and its differences with

CBI dehydration pathways, one can begin to create a framework to assess the lifecycle emissions of CBI dehydrated anhydrous ethanol by isolating the dehydration process and ocean transport of ethanol. Molecular sieve technology is well established, popular, and thought by some to be the industry standard for Brazil and the Caribbean to convert hydrous ethanol into anhydrous ethanol. Various companies construct these systems, including Praj of India, Delta-T of Williamsburg, Virginia, and Dedini of Brazil. The process is described in Appendix A. (CANOPY)

Comment: The dehydration process requires steam energy to heat and cool the ethanol as described in Appendix A. As noted on page 12 CARB923, this energy is typically generated from burning waste bagasse and is not counted in the Lifecycle Analysis of Brazilian anhydrous sugarcane ethanol. In the Caribbean, however, the energy to create steam is generated by burning fossil fuels, which vary by plant. These fuels range from natural gas, which is primarily used in Trinidad because of its abundant availability (Trinidad is so rich in natural gas production that it is a major exporter of liquefied natural gas to the U.S. and other destinations), to #2 distillate (diesel fuel) and #6 oil (bunker). Diesel fuel and bunker are primarily used in dehydration plants located outside of Trinidad. We urge ARB to differentiate in the Method I look-up charts between the various CBI ethanol dehydration facilities based on the type of fuel that they burn. (CANOPY)

Response: This modified pathway can be done by Method 2A, with verifiable data and completion of a rulemaking.

V-50. Comment: When determining the initial carbon footprint(s) of ethanol dehydration plants in Trinidad that are fueled by natural gas, ARB should make note that natural gas produced in Trinidad may have a lower life-cycle carbon footprint than natural gas in the U.S.. First, Trinidad uses the latest in production technology. Given Trinidad's natural gas driven economy and its status as a leading exporter of LNG, it has significant incentive and funding for some of the most efficient technology available. Second, the natural gas pipelines are relatively new and well maintained, using predictive and preventive maintenance regimes. This further reduces fugitive emissions. Third, natural gas in Trinidad travels less than 50 miles from the natural gas processing plant to the dehydration facilities, further reducing the opportunity for fugitive emissions while being transported. For comparison, Los Angeles County, California is more than twice as large as the combined area in square miles of both Trinidad and Tobago. (CANOPY)

Response: The commenter may provide data to support the claim and those data could be used in a modified pathway under Method 2A.

V-51. Comment: CARB923 provides a framework under which the increased GHG lifecycle emissions from CBI dehydration fueled by natural gas may be

completely offset with increased domestic distribution via the grid of co-product electricity from Brazilian ethanol production facilities. Pages 42 to 44 of CARB923 describe the process of accounting for co-product credit from electricity generation in Brazil. Since the same technology is used in Brazil and in CBI countries to dehydrate ethanol, the same amount of energy should be generally required to power the dehydration process in Brazil and the CBI. Under an electric tri-gen scenario, energy normally used at the Brazilian mill to convert hydrous ethanol into anhydrous ethanol would be used to generate additional electricity for distribution via the grid, thus creating additional GHG emission credits. These credits would be used to offset any potential GHG emissions from ethanol dehydration at a CBI ethanol dehydration plant burning natural gas. Moreover, since these credits are derived by displacing electricity generated from natural gas in Brazil, hydrous ethanol transformed into anhydrous ethanol at a CBI ethanol dehydration plant using natural gas should have the same lifecycle GHG emissions as anhydrous ethanol dehydrated at a mill in Brazil insofar as the dehydration process is concerned and so long as the Brazilian mill is equipped to distribute co-product electricity. (CANOPY)

Comment: Additional GHG emissions as a result of dehydrating ethanol in the Caribbean instead of at the mill in Brazil may be derived as result of the increased distance that the ethanol must travel to and from the CBI dehydration plant away from the direct route. CARB923 lists on page 34 the energy intensity on a BTU/tonne-mile basis for ocean transportation. Additional miles from the base Brazil port direct to California would be calculated on this basis. (CANOPY)

Comment: Our recommendation for multiple pathways through the CBI is in line with ARB's existing multiples pathway methodology detailed in CARB923. Indeed, differentiating between ethanol dehydrated at different dehydration facilities should be less difficult than differentiating ethanol from various pathways in Brazil at the Brazilian port. Brazilian ports are known to be congested and short on tank capacity, thus requiring product comingling in the tanks. In contrast, ethanol from different dehydration facilities will probably arrive to California in different ships. Even if shipped in the same vessel, we believe that it would be held in different tanks for quality and volume control purposes. (CANOPY)

Response: This could be addressed under Method 2A revision when verifiable data can be provided.

Biodiesel and Renewable Diesel

V-52. Comment: §95480.1(c)(2): This section exempts LPG (or "propane") from the LCFS regulation. This exemption creates a problem for the renewable propane that is coproduced with renewable diesel. It denies this perfectly good low carbon fuel a role in the LCFS. To resolve this problem you could keep LPG in the LCFS. But doing so would create a lot of paperwork and record keeping to

track a relatively small volume of renewable fuel use in a relatively small market segment. Even if you acknowledge that renewable propane and fossil propane are chemically identical and treat renewable propane like renewable electricity (the renewable producer mixes the renewable product with non-renewable product and then sells the right to the buyer to call his purchase of fungible product renewable) there would be a lot of recordkeeping for no benefit. (The carbon reduction occurs regardless of whether the accounting is difficult or easy.) It would be much more efficient to modify the renewable diesel lifecycle analyses to allow the net renewable propane energy and carbon to be credited to the renewable diesel production and to leave the propane exemption in **§95480.1(c)(2)** in place. (A204NESTE5)

Response: Propane is credited in the renewable diesel production as co-product; however, it is exempt from the LCFS due to its limited market value and usage.

V-53. Comment: §95486(b)(1)(O) The pathway “Stationary Source Division, Air Resources Board (September 23, 2009, v.12), “Detailed California-Modified GREET Pathway for Co-Processed Renewable Diesel Produced in California from Tallow (U.S. Sourced);” is not ready to become law.

The assumption that co-processed renewable diesel is distributed by truck is simply false. Co-processed renewable diesel will not be separated from the ULSD that it is processed with. Therefore its distribution energy and carbon numbers should be identical to ULSD.

	Energy, Btu/mmBtu	Emissions, gCO ₂ e/MJ
Renewable Diesel	8662	0.66
ULSD	4721	0.33
Difference	3941	0.33

Admittedly this is not a big error, but methodology should match reality. Separately processed renewable diesel will also be blended with ULSD prior to distribution because that is the optimum blending location. If the renewable diesel production facility is adjacent to a refinery its distribution energy and emissions will be identical to ULSD. If the renewable diesel facility is not adjacent to a California refinery then there should and will be energy and emissions factors associated with delivering it to the refinery. (A204NESTE5)

Response: The two routes of the fuels transportation and distribution (T&D) are different: ULSD transportation has 80 percent moved by pipeline, 20 percent by heavy duty (HDD) trucks, and 99.4 percent ULSD distribution by HDD trucks (estimated 0.6 percent directly from pipeline to stations). Renewable diesel T&D are assumed quite different. ARB staff estimated that 80 percent of renewable diesel is moved by HDD trucks, 20 percent directly from the plant to stations, while 100 percent renewable diesel distributed by HHD trucks. Staff will review this as facilities come on line to determine if modifications are required.

V-54. Comment: Tank to wheels emissions. Another small but needed for reality adjustment involves the tank to wheels emissions. The Biodiesel Renewable Diesel Research Program is confirming that renewable diesel reduces the tank to wheel emissions relative to CARB ULSD. This adjustment only amounts to a little over a tenth of a gCO₂e/MJ. Consistent application of the adjustment will also increase tank to wheels emissions for biodiesel. But, we really must make methodology match reality because the integrity of the LCFS depends on paying attention to the details of reality. (A2O4NESTE5)

Response: This is recognized and the renewable diesel TTW CO₂ vehicle is calculated at 72.62 g/MJ compared to 74.10 g/MJ of ULSD, which is higher.

V-55. Comment: The lifecycle analysis pathway can be simplified by acknowledging that renewable diesel production processes are really just renewable fuel production processes. Renewable diesel can simply bear all of the energy and fossil carbon inputs to the pathway less relatively small renewable propane energy and CO₂ credits. We do not have to wonder if we should allocate based upon weight, value, or energy content. We simply let the desired product carry the load and take credits for the renewable fuel byproducts just like the bagasse energy and CO₂ credits taken in the “Detailed California-Modified GREET Pathway for Brazilian Sugarcane Ethanol.” This methodology is simpler and more robust than the pathways that have non energy co-products and therefore is the appropriate pathway for this product. (A2O4NESTE5)

Response: We believe our approach to lifecycle analysis, where all co-products are considered, is necessary to provide an accurate assessment of carbon intensities.

V-56. Comment: We are also concerned about the diesel compliance pathways. The most abundant biodiesel pathway, based on soybean feedstock, has yet to be assigned carbon intensity. (WSPA5)

Response: ARB Staff is working with UC Berkeley and related parties to finalize the soybean feedstock for biodiesel soon. As indicated in Section I.A., ARB plans to make the carbon intensity value and pathway document available for public comment soon, and to adopt those as part of this rulemaking before March 4, 2010.

V-57. Comment: First, we are concerned regarding the lack of registration requirements for the biofuel producers to define the carbon intensity of their products. As purchasers of their products we need assurance that the carbon intensity of each product has been determined and accepted by ARB, and that the demonstration of a physical pathway (needed for credit generation in 2011) has also been accepted by ARB. (WSPA5)

Response: Staff is developing a registration process to facilitate use of the alternative fuels. It was not necessary to mandate registration. This process will be evaluated

during the 2010 reporting only period and if it is found to be appropriate, this can be added to the regulation before compliance is required in 2011. The Lookup Tables in section 95486(b) of the the adopted regulation identify carbon intensities of 37 gasoline alternatives (Table 6) and 25 diesel alternatives (Table 7). Sufficient pathways are now included in the look up tables as part of the regulation for regulated parties to comply with the regulation.

High Carbon Intensity Crude Oil

V-58. Comment: The process for determining which crude oils are high carbon intensity crudes also lacks clarity. This is particularly important, since refiners will need to make crude purchase decisions before it is known whether a crude oil is a high carbon intensity crude or not. (WSPA5)

Comment: In addition to the lack of look-up table values for high carbon intensity crude oil (HCICO) there is a lack of clarity in how to determine whether or not a crude oil is in fact a HCICO if it is not part of the “baseline” California crude mix. ConocoPhillips requests that ARB provide lists of crude oils that are: 1) high carbon intensity and are not included in the California “baseline”; and 2) not high carbon intensity and are not part of the California “baseline.” These lists need to be more specific than merely defined by what country the crude was sourced from as some countries have multiple producing fields and production approaches with perhaps different carbon intensities. (CONOCO3)

Response: Staff is directed by the Board in Resolution 09-31 to make this information available. This process is underway and information will be made available to the public. The actual quantification of individual high carbon intensity crude oils will be accomplished using Method 2B.

V-59. Comment: Also, we believe that section 95486(b)(2)(A)(2)(a) regarding the deficit calculation when HCICO is used is confusing and overly complex. We recommend a simpler approach such as: taking a difference in carbon intensity of HCICO (expressed in gCO₂e/MJ); subtracting 15 gCO₂e/MJ (the “threshold” value); applying the percentage of HCICO used during the compliance period; applying a ratio of CARBOB to CARB diesel production; and adding the respective deficit (in gCO₂e/MJ) to the fuel standard for each fuel pool. This approach would also prevent possible confusion wherein different CARBOB’s and different CARB diesels may be perceived to have different carbon intensity values. (CONOCO3)

Response: The calculation proposed in the regulation is based on WSPA’s recommended Incremental Deficit calculation methodology, which is equivalent to the proposed approach addressed in the comment. The equation in the regulation is directly adopted from the WSPA’s proposal submitted to ARB in July 2009, with small changes in variables and other notations. Since WSPA’s written proposal, staff has met with WSPA’s representative to evaluate the equations in detail. It was agreed that

WSPA's proposal will be used in credit/deficit calculations regarding HCICO. Additionally, staff has submitted a spreadsheet showing how the Reporting Tool will calculate the credits/deficits for various HCICO/non-HCICO scenarios. Staff believes any question regarding the complexity of the equation regarding HCICO should be directly addressed to the WSPA representative on this matter.

V-60. Comment: It is not clear why the Executive Officer has decided to add or modify pathways for some production processes. We object to the procedures that the Executive Officer is using in order to include the additional pathways in the proposed Lookup Table. We have seen no formal or informal requests for the additions of the new pathways in the public record. But it is certain that any stakeholder in the LCFS regulatory process that does not seek to have carbon intensity values added to the Lookup Table now will be consigned to an open-ended and potentially indefinite review process under Method 2 that will place it at a significant disadvantage, and that will limit the options of the energy companies that would benefit from a diversity of different compliance strategies for the LCFS regulation. (POET3)

Response: The pathways that were developed and incorporated into the Lookup Table were consistent with Resolution 09-31. We have sought to include all pathways for which there is sufficient supporting data and analysis at this time.

- **V-61. Comment:** Our primary concern is the longer term compliance uncertainty due to the speculative nature of the regulation. Clearly, without new chemistry and engineering breakthroughs, we question the ability of the regulated parties to comply as required in a matter of a few years. Our previous comments on these issues remain valid. (WSPA5)

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- **Response:** See response to Comment J-3.

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V-62. Comment: The updated Executive Summary to the ISOR (pp. 25-26) notes that the board directed staff to report back, presumably at the December 2009 meeting, on rulemakings conducted to revise Energy Economy Ratios and the list of opt-in low carbon fuels. We continue to work with staff to develop appropriate EERs for heavy-duty natural gas engines to appropriately account for the increased efficiency of compression ignition engines. It is our hope and expectation that at the December board meeting the board will have an opportunity to adopt these changes to the EERs and to incorporate North American LNG liquefied in California at a 90 percent efficiency factor into the list of opt-in fuels that are compliant with the 2020 low carbon target. Even using the ARB's current EER values, this LNG pathway is almost six percent below the 2020 compliance target. Based on the final decision on EER values for heavy duty natural gas engines, other LNG pathways may also qualify to be included as opt in fuels. (CNGVC4)

Response: The ARB staff will not be proposing any regulatory changes, including changes to the EERs for heavy duty natural gas engines, for the Board's consideration at the December 2009 meeting. Resolution 09-31, adopted by the Board April 28, 2009, delegates to the Executive Officer the authority to conduct and complete rulemakings related to changes in the EER values, and directs the staff to reevaluate the EERs for heavy duty vehicles fueled by compressed and liquefied natural gas, and, if appropriate, update the EER values as soon as practical. The staff is currently evaluating the need to change the EERs for heavy duty natural gas engines in consideration of heavy duty natural gas engines that are currently being certified to the ARB's 2010 emission standards. The staff will comply with the Resolution's requirement to make any changes, if appropriate, to the heavy duty EERs values for CNG and LNG as soon as practical, but has not yet reached a decision on if and when to change these EER values. The updated Executive Summary to the ISOR was released for purposes independent of this rulemaking; it is not part of the rulemaking file and is not being relied upon.

D. Environmental Impacts

Multimedia Analysis

V-63. Comment: Caterpillar believes that promoting much greater use of renewable fuels (by and through the LCFS) should only be done in parallel with a thorough investigation of the implications and compatibility of the various renewable fuels/fuel blends with the engine technologies and we appreciate staff's initial efforts in this space. In addition to this broad "compatibility" issue, there are potentially other consequences of using these renewable fuels that necessitate further review. By other consequences, for one, we are referring to the emissions output and how that might change depending on the renewable fuel used and/or the amount of renewable fuel blended with diesel fuel.
(CATERPILLAR)

Response: As noted in Chapter VII of the ISOR, the LCFS does not, by itself, establish a motor vehicle fuel specification. It simply assigns a carbon intensity value to each fuel or blendstock based on an analysis of that fuel/blendstock's fuel lifecycle. The overall carbon intensity of a regulated party's transportation fuels pool is then required to meet a yearly carbon-intensity reduction schedule. By its terms, the LCFS regulation under section 95480.1(e) does not amend, repeal, modify, or change in any way the existing State specifications or other State or federal requirements on motor vehicle fuels.

New and existing fuels that comply with the LCFS regulation will be essentially indistinguishable from comparable fuels that comply with other State and federal regulations. To illustrate, gasoline with 85 percent ethanol (E85) that meets the LCFS regulation should be chemically indistinguishable from E85 that meets ARB requirements set forth in section 2292.4, title 13, CCR. This was discussed on page V-30 of the Staff Report.

The only substantive difference between the two versions of E85 noted above should be the carbon intensity (i.e., the GHG contributions) of the process used in making the ethanol. For example, one E85 may be sourced from sugarcane, while the other is sourced from corn – both are chemically identical versions of ethanol, but there would be a substantial difference in their carbon intensity from the fuel lifecycle of both versions of ethanol. Carbon intensity is not an inherent chemical property of a fuel, but rather it is reflective of the process in making, distributing, and using that fuel. Because both types of E85 in the above example are essentially identical, there should be no substantive difference in their impacts on engine performance or their compatibility with engine components or emissions treatment systems.

Further, under section 95480.1(e) a person subject to the LCFS regulation is solely responsible for ensuring compliance with the LCFS requirements and other applicable State and federal requirements. This includes, but is not limited to, “obtaining any necessary approvals, exemptions, or orders from either the State or federal government.” The key federal requirements for motor vehicle fuels are set forth in title 40, Code of Federal Regulations (CFR), part 79. Under section 79.4(a) of 40 CFR 79, manufacturers of motor vehicle fuels are required to register their fuels with the U.S. EPA. All such fuels and fuel additives, including biodiesel and other renewable fuels, are subject to this registration requirement and must be registered before the fuels can be sold, offered for sale, or introduced in commerce in the U.S. Thus, new fuels and fuel additives that are formulated in the future to meet the LCFS but are not already registered with U.S. EPA would need to undergo the registration process set forth in 40 CFR Part 79, as well as needing to meet State regulations promulgated by ARB or the Division of Measurement Standards.

The federal registration process requires, among other things, a demonstration of the effects of the fuel's emission products on the performance of emission control devices/systems (e.g., see 40 CFR §79.32(d)(6) for motor vehicle gasoline). Under sections 79.51(k) (General Requirements and Provisions) and 79.54(g)(2) (Other Tier 3 Testing), U.S. EPA also has the ability to require additional testing to evaluate concerns arising from the potential effects of a fuel on the performance of emissions control equipment. Thus, if information becomes available that suggests there may be performance or compatibility issues with the new fuels or fuel additives, U.S. EPA is required under 40 CFR Part 79 to investigate the issues and determine if there are adverse impacts to engines and engine systems.

Under the law, U.S. EPA is required or otherwise authorized under 40 CFR Part 79 to mandate extensive engine testing to ensure that performance issues with the use of new fuels are identified and addressed before such fuels are introduced into commerce in the U.S., including California. Because of this, the primary responsibility for ensuring compatibility of new fuels with engine systems rests with U.S. EPA.

Impacts of New Fuels on Engines

V-64. Comment: Two interrelated issues of significant concern are certification fuel and certification testing. Caterpillar believes it is very premature to discuss any changes to the current diesel engine certification testing process or the current certification fuel used in that process. Renewable fuels currently available in the marketplace significantly vary in compositions and quality. Engine manufacturers should not be required to test or otherwise demonstrate compliance to a variety of possible renewable fuels or blends. That would be extremely cumbersome, cost prohibitive, and not practical. (CATERPILLAR)

Response: As noted in the previous response, the LCFS does not, by itself, establish any motor vehicle fuel specification. Therefore, there is no requirement under the LCFS regulation for engine manufacturers to begin testing their engines or otherwise demonstrate compliance or compatibility with existing and already-registered renewable fuels. To the extent renewable fuels under the LCFS are essentially identical to already-registered renewable fuels, no additional testing should be needed under 40 CFR 79. But to the extent fuel providers seek to introduce new renewable fuels into commerce to reduce their fuel-pool carbon intensity, those new fuels may need to undergo engine testing pursuant to 40 CFR Part 79, as noted in the previous response.

V-65. Comment: An engine manufacturer should not be liable, or implicitly accountable, for emissions when a fuel different than the certification fuel, is used. While we appreciate ARB's current efforts in analyzing fuel impacts on emissions, the certification tests in question are based on using a well-defined certification fuel and need to continue in this course. (CATERPILLAR)

Response: The LCFS regulation applies primarily to "regulated parties" as that term is defined in the regulation in section 95484(a). Regulated parties are primarily transportation fuel providers, such as refiners, producers, importers, energy utilities, and similar entities. Engine manufacturers would only be subject to the LCFS requirements to the extent they are also "regulated parties." To ARB staff's knowledge, there are no engine manufacturers that also fall within the definitions of "regulated party" set forth in section 95484(a). Therefore, engine manufacturers are not liable or implicitly accountable for GHG emissions under the LCFS regulation.

To the extent ARB continues to develop and promulgate new motor vehicle fuel specifications, such as the current effort to establish specifications for biodiesel and renewable diesel, the staff's use of certification tests based on a well-defined certification fuel will continue as part of such rulemaking activities.

V-66. Comment: ARB needs to provide assurance and enforcement for the technical and quality specifications of both the renewable fuels and the resulting "finished" fuel blends in the market. This enforcement of current renewable fuels and 'finished' fuels to the latest industry specifications and standards by ARB will be critical to the success of the LCFS. Thus, ARB will need to continue to approve transportation fuels and ensure that they meet the latest industry specifications and standards. In addition to adequate enforcement, transparency to the end

user about the “finished” fuel being purchased will be another important element of assuring the market about the quality and consistency of the transportation fuel pool. (CATERPILLAR)

Response: As noted previously, the LCFS does not, by itself, establish motor vehicle fuel specifications. Thus, fuels sold under the LCFS program must also meet current ARB motor vehicle fuel specifications. These specifications will continue to be enforced by ARB enforcement staff.

It goes without saying that ARB enforcement staff will also extend their enforcement activities to encompass new or amended fuel specifications when ARB conducts such rulemakings in the future.

V-67. Comment: There is significant uncertainty with today’s bio-diesel fuels (FAME), and despite their availability, there is a lack of adequate clarity to their effects, shorter term and longer term. Engine manufacturers need predictability and consistency of fuel in order to design future engine technologies. Because of this, engine manufacturers need adequate lead-time to develop the requisite technologies that offer optimum performance, coupled with the most cost effective GHG reductions. (CATERPILLAR)

Response: As noted in the response to Comment V-64, the need to identify and address the effects of biodiesel fuels on engine performance and compatibility is primarily within the U.S. EPA’s purview under 40 CFR Part 79.

It should be noted that engine manufacturers have been, and will continue to be, important stakeholders that participate in rulemakings to amend or establish fuel specifications at both the State and federal levels. We expect this will be no different for State rulemakings that follow and implement the LCFS through new or modified fuel specifications. Because such specifications typically take 1-2 years to develop and have several years of built-in lead time, we do not anticipate the lead times for engine manufacturers will be inadequate.

V-68. Comment: Caterpillar believes the reduction of GHG emissions and the most efficient use of energy from transportation fuels can best be achieved by:

- All new fuels must be compatible with and applicable to current and future technology engines, fuel systems and emissions reduction technologies.
- All new fuels must meet the latest industry fuel standards and specifications.
- There must be transparency to the consumer about the fuels being purchased.
- There must be adequate enforcement by EPA of renewable fuels and “finished” fuels to industry standards and specifications. (CATERPILLAR)

Response: We generally agree with these comments and have addressed them in the previous responses in this section.

V-69. Comment: To the extent policy-makers seek to promote fuels that affect the engine, fuel system, after treatment system and/or emissions, sufficient lead time and stability must be provided to engineer products capable of meeting any new regulatory requirements and to operate reliably and efficiently on new fuels.

Lead times are particularly crucial if any impact on certification fuel and emissions standards will result. (CATERPILLAR)

Response: As discussed in the responses to the preceding six comments, we do not expect the LCFS regulations adopted in this rulemaking will have any impact on certification fuel or motor vehicle emission standards, or on the reliable and efficient operation of motor vehicles.

V-70. Comment: Because alternative and renewable fuel capabilities and performance characteristics vary by product, it is critical that consumers clearly understand what fuel is being offered for sale so they can make informed choices in concert with the capabilities of the engines in their vehicles and other products. This is particularly true for fuels that are not a drop-in replacement of diesel or are chemically different. (CATERPILLAR)

Response: The Federal Trade Commission (FTC) has promulgated specific labeling requirements for methanol, ethanol, biodiesel and biomass-based diesel, and other alternative liquid automotive fuels under 16 CFR 306 (see 73 FR 40154-40165, December 16, 2008). The FTC regulation sets forth clear specifications for, among other things, the accurate automotive fuel rating of such fuels. Specifically for biodiesel and biomass-based diesel fuels, fuel suppliers must rate and label accordingly those fuels that contain:

- (1) "B-20 Biodiesel Blend" (contains biomass-based diesel or biodiesel in quantities between 5 percent and 20 percent);
- (2) "20 percent Biomass-Based Diesel Blend" (contains biomass-based diesel or biodiesel in quantities between 5 percent and 20 percent);
- (3) "B-100 Biodiesel" (contains 100 percent biodiesel); and
- (4) "100 percent Biomass-Based Diesel (contains 100 percent biomass-based diesel).

Diesel blends containing more than 20 percent biodiesel or biomass-based diesel are also required to meet similar labeling requirements. Further, ethanol, methanol, and other alternative liquid fuels are subject to similar labeling requirements under 16 CFR 306.

For biodiesel and biomass-based diesel, the FTC's requirements are designed to "inform consumers of the percentage of biodiesel or biomass-based diesel contained in a fuel." *Id.* at 40162. Commenters to the FTC rulemaking generally agreed with the categories of information disclosed on the labels and that the labels "provide the consumer with the information necessary to fuel properly his/her vehicle." *Id.* at 40157.

Based on these reasons, the FTC requirements should prove adequate for providing consumers with sufficient information so they can make informed choices. Having said that, we look forward to working with engine manufacturers, fuel providers, and other stakeholders to identify the most efficient and effective ways to inform consumers as suggested by the commenter. We are aware that stakeholders such as the National Biodiesel Board already have such efforts underway. We are open to exploring these and other efforts to leverage our current outreach with other private and public outreach programs.

ATTACHMENT A

NONSUBSTANTIAL MODIFICATIONS MADE TO THE LCFS REGULATION AFTER RELEASE OF THE SECOND 15-DAY CHANGES NOTICE

1. Identification of GTAP Model by date (sections 95481(a)(20.5) and 95486(c)(3)).

Section 95486(c)(3) incorporates by reference the GTAP Model. A nonsubstantial modification to section 95486(c)(3) identifies the referenced model by date – “the GTAP Model (February 2009).” A new section 95481(a)(20.5) defines “the GTAP Model (February 2009)” as a software package containing specified computer files dated February 2009 and posted on the Air Resources Board’s website. 1 CCR section 20(c)(4) requires incorporated documents to be identified by date; the February 2009 GTAP model is the version of the model staff has been using in this rulemaking.

2. Acronym “ASTM” (section 95481(b)(1)). This subsection identifies the acronym “ASTM” as meaning “ASTM International” – an entity formerly known as the American Society for Testing and Materials. To avoid any confusion, a nonsubstantial modification adds “(formerly American Society for Testing and Materials)” at the end of the line.

3. Evidence of physical pathway (section 95484(d)(2)). In the modifications made available with the First 15-Day Changes Notice, the changes to section 95484(d)(2) were confusing in that relettered subsections (C)-(G) were not intended to follow and be at the same level as the added (A) and (B). Nonsubstantial modifications made what had been “(A)” and “(B)” an integrated part of the first paragraph of (d)(2). As had been the case with the original proposal, subsections (A)-(G) are a list of the requirements for Executive Officer approval as introduced in the third paragraph of (d)(2). References to these subsections were corrected as well.

4. Energy densities (Table 4 in section 95485(a)(1)). A commenter identified an error in Table 4 (section 95485(a)(1)), which erroneously listed one entry as “Neat denatured Ethanol.” This is in error because “neat” refers to 100% ethanol, while “denatured” refers to nearly 100% ethanol with a small amount of denaturant (typically gasoline) to make the ethanol indigestible. The context of Table 4 is to show the energy density of various LCFS fuels and blendstocks, which means the values in Table 4 must correspond to pure fuels and pure blendstocks. To correct this error, a nonsubstantial modification to this entry was made so that the result shows “Anhydrous Ethanol.” Anhydrous ethanol is pure ethanol without denaturants or even water (hence the “anhydrous”). “Anhydrous” is a well-established term of art in the affected industry, and its use is consistent with the original context of Table 4. The energy density shown in Table 4 for this fuel is unchanged.

5. References to ARB Pathway documents (section 95486(b)(1)(J) through (O)).

The identification of the versions of the September 23, 2009 Air Resources Board Pathway documents incorporated by reference was corrected to reflect exactly the

identification the of versions of these Pathway documents as they were made available with the September 23, 2009 Second 15-Day Changes Notice. (e.g., “v.2” was changed to “v.2.0” as indicated).

6. Removal of pathway placeholders in section 95486(b)(1) Table 7). The soybean pathway placeholders were removed from Table 7 since these pathways will be added in a later action in this rulemaking.

7. Illustrative example (section 95486(b)(2)(B)). An illustrative example was provided in section 95486(b)(2)(B) to assist stakeholders in reading Tables 6 and 7 and extracting the appropriate carbon intensity value for a given situation. In the originally proposed text, the illustrative example used ethanol produced from the fermentation of cellulosic feedstock derived from farm trees. At the time the Staff Report was published, staff had expected this fuel pathway to be incorporated into Table 6, but the cellulosic ethanol pathway was never completed due to various reasons. Unfortunately, the illustrative example remained in the modified text made available with the First 15-Day Changes Notice and Second 15-Day Changes Notice. This nonsubstantial modification uses an illustrative example based on a compressed natural gas (CNG) vehicle using CNG derived from dairy digester biogas.

8. References to California Administrative Procedure Act (section 95486(f)(4) and (5)). Citations to the APA provisions on administrative regulations and rulemaking were corrected to “11340 et seq.”

9. Formatting subsections with subheadings. Throughout the Final Regulation Order, where a subsection heading is not immediately followed by a subsection of the next level down, the text following the subsection heading was uniformly made to follow the subsection heading without a paragraph break.

ATTACHMENT B

Summary of the Health Impacts Associated with Emissions from Potential Biorefineries (Edited October 2009)

An analysis of health impacts of the Low Carbon Fuel Standard was included in the March 2009 document entitled “The Proposed Regulation to Implement the Low Carbon Fuel Standard, Staff Report: Initial Statement of Reasons”. While the conclusions of the analysis have not changed, minor adjustments to the impacts have been made using updated emissions factors. The potential health impacts have been reduced slightly as a result of the updated factors. In addition, in response to public comments, this update includes expanded analysis to put the estimated health impacts in perspective as they relate to the benefits of other components of the LCFS program. Finally, the relationship between health impacts due to the LCFS program and impacts due to the federal RFS program are also examined for potential overlap. The references used in the update are identical to those cited in the ISOR and submitted for public record.

The health impacts analysis published in March 2009 calculated seven non-cancer health impacts that could result from emissions from new biorefinery operation in California and emissions from the transport of imported fuel (ethanol and biodiesel) into the state. The analysis has been edited to clarify the fact that these are impacts that, if considered without regard to benefits of the LCFS, would increase the number of premature deaths, hospital admissions due to respiratory or cardiovascular causes, cases of asthma-related and other lower respiratory symptoms, cases of acute bronchitis, and number of work loss and minor restricted activity days.

The analysis also now incorporates emission factors from an updated emissions model (EMFAC 2007v2.3) to calculate emissions from biorefinery truck transportation and from transporting imported fuel. The slightly revised emissions calculations have lowered the previously published estimates of health impacts.

ARB staff received comments and questions about the relationship between the health impacts due to biorefinery transportation and imported fuel transport calculated in the staff report and the health *benefits* of other components of the LCFS program. In response to these comments, staff has included the health benefits that could result from the increased use of advanced vehicles in California.

Finally, the analysis examines the impact of the requirements of the federal RFS2 program and what portion of the health impacts attributed to the LCFS would also occur under the federal requirements. Staff has concluded that under the majority of scenarios examined, emissions attributed to the LCFS would occur under the federal program also if the LCFS did not exist. As shown in Table F11-4, estimates of the volume of ethanol and diesel fuel that will be produced in California and imported into the state due to the federal program are in most cases greater than the volume of these

fuels included in the LCFS scenarios. Therefore, health impacts that could occur as a result of the LCFS program could potentially also occur in the absence of the LCFS program. The analysis recognizes and clarifies this potential programmatic overlap.

Table 1 below compares the number of potential health impacts that could occur as a result of biorefinery transport presented in the staff report to the number of potential health impacts using updated emissions factors. Also shown are the potential health impact benefits of the use of 1,000,000 advanced vehicles in California.

Table 1: Summary of the Potential Health Impacts and Benefits Associated with Emissions Related to Possible Biorefineries and Advanced Vehicles in Year 2020

Endpoint	Additional Potential Cases due to Biorefinery Transport Emissions (As reported in ISOR)	Additional Potential Cases due to Biorefinery Transport Emissions (Update from ISOR)	Fewer Potential Cases as a result of Advanced Vehicle Benefits (1)
Premature Death	+24	+20	-130
Hospital Admissions (Respiratory & Cardiovascular)	+8	+7	-46
Asthma & Lower Respiratory Symptoms	+340	+290	-2,200
Acute Bronchitis	+27	+24	-180
Work Loss Days	+2,200	+1,900	-14,000
Minor Restricted activity days	+13,000	+11,000	-82,000

(1) Based on 1 million advanced vehicles (benefit difference between 2 million market-driven advanced technology vehicles and 1 million improved ZEV regulation vehicles).

Appendix F11

Health Impacts Associated with Emissions from Potential Biorefineries

(edited October 2009)

A. Health Impacts Assessment

A substantial number of epidemiologic studies have found a strong association between exposure to ambient PM_{2.5} and a number of adverse health effects.²⁸ For this report, ARB staff quantified seven non-cancer health impacts associated with the change in exposure to NO_x and PM_{2.5} emissions from increased transportation associated with new biorefineries and transporting imported ethanol within California. This analysis has been edited since the March 2009 ISOR was published to include 1) updated emissions factors, 2) the potential emissions benefits of advanced vehicles and 3) recognition of the potential programmatic overlap with the federal RFS2 program.

A comparison of the potential health impacts reported in the March 2009 ISOR with the slightly lower impacts using updated emission factors is shown in Table F11-1. Also included are the potential health benefits of the use of 1,000,000 advanced vehicles in California.

Table F11-1
Summary of the Potential Health Impacts and Benefits Associated with Emissions Related to Possible Biorefineries and Advanced Vehicles in Year 2020

Endpoint	Additional Potential Cases due to Biorefinery Transport Emissions (As reported in ISOR)	Additional Potential Cases due to Biorefinery Transport Emissions (Update from ISOR)	Fewer Potential Cases as a result of Advanced Vehicle Benefits (a)
Premature Death	+24	+20	-130
Hospital Admissions (Respiratory & Cardiovascular)	+8	+7	-46
Asthma & Lower Respiratory Symptoms	+340	+290	-2,200
Acute Bronchitis	+27	+24	-180
Work Loss Days	+2,200	+1,900	-14,000
Minor Restricted activity days	+13,000	+11,000	-82,000

(a) Based on 1 million advanced vehicles (benefit difference between 2 million market-driven advanced technology vehicles and 1 million improved ZEV regulation vehicles).

²⁸ CARB, 2002. California Air Resources Board and Office of Environmental Health Hazard Assessment. Staff Report: Public Hearing to Consider Amendments to the Ambient Air Quality Standards for Particulate Matter and Sulfates, available at <http://www.arb.ca.gov/research/aaqs/std-rs/pm-final/pm-final.htm>

1. Updated Emission Factors

The health impacts of potential biorefineries in 2020 have been updated from the published staff report version (March 2009). Emission factors from an updated emissions model (EMFAC 2007v2.3) were used for these calculations.

These health impacts are estimated to be a result of the increased biorefinery transportation emissions only and might be expected if there were no emissions benefits resulting from other components of the LCFS.

This analysis shows that the statewide health impacts of the emissions associated with new biorefinery transportation and ethanol import transportation in year 2020 are approximately:

- 20 premature deaths (6 – 38, 95% CI)
- 7 hospital admissions due to cardiovascular and respiratory causes (4 – 10, 95% CI)
- 290 cases of asthma-related and other lower respiratory symptoms (120 – 460, 95% CI)
- 24 cases of acute bronchitis (0 – 49, 95% CI)
- 1,900 work loss days (1,700 – 2,200, 95% CI)
- 11,000 minor restricted activity days (9,300 – 13,000, 95% CI)

Table F11-2 lists the impacts associated with primary PM and secondary PM emissions. The methodology for estimating these health impacts is described below, and details can be found in Appendix A of the Emission Reduction Plan for Ports and Goods Movement in California.²⁹

²⁹ CARB, 2006. California Air Resources Board. Emission Reduction Plan for Ports and Goods Movement, available at http://www.arb.ca.gov/planning/gmerp/march21plan/appendix_a.pdf

Table F11-2
Total Health Impacts Associated with Emissions Related to Possible Biorefineries
and Transportation of Imported Ethanol and Biodiesel in Year 2020^a
Emission Factors Updated from March 2009 Staff Report

Endpoint	Pollutant	# of Additional Cases 95% C.I. (Lower Bound)	# of Additional Cases (Mean)	# of Additional Cases 95% C.I. (Upper Bound)
Premature Death	PM	1	3	6
	NOx	6	17	32
	<i>Total</i>	6	20	38
Hospital admissions (Respiratory)	PM	0	0	1
	NOx	1	2	3
	<i>Total</i>	1	2	4
Hospital admissions (Cardiovascular)	PM	0	1	1
	NOx	3	4	5
	<i>Total</i>	3	5	6
Asthma & Lower Respiratory Symptoms	PM	17	45	72
	NOx	99	250	390
	<i>Total</i>	120	290	460
Acute Bronchitis	PM	0	4	8
	NOx	0	20	41
	<i>Total</i>	0	24	49
Work Loss Days	PM	240	290	330
	NOx	1,400	1,700	1,900
	<i>Total</i>	1,700	1,900	2,200
Minor Restricted Activity Days	PM	1,400	1,700	2,000
	NOx	7,900	9,600	11,000
	<i>Total</i>	9,300	11,000	13,000

^a Health effects from primary and secondary PM are labeled PM and NOx, respectively. The sum of PM and NOx impacts may not equal the total given due to rounding.

2. LCFS Advanced Vehicle Emissions Benefits

In response to public comments, staff has edited the health impacts analysis to include the health benefits that could result from the increased use of advanced vehicles in California. A reduction in criteria pollutant emissions from transportation fuels including NOx and PM2.5 is expected in the future as a result of increased penetration of advanced vehicles and CNG vehicles. The magnitude of the emissions benefits, and the resulting health impact benefits, is difficult to estimate at this time due to the number of possible scenarios that could result from the LCFS regulation and the ZEV regulation. In addition, benefit analysis would depend on complete multimedia evaluations of any future biodiesel formulations that could result from new specifications.

Table F11-3 lists the impacts associated with primary PM and secondary PM emissions and includes benefits associated with advanced vehicles. The methodology for estimating these health impacts is described below, and details can be found in Appendix A of the Emission Reduction Plan for Ports and Goods Movement in California.³⁰

³⁰ CARB, 2006. California Air Resources Board. Emission Reduction Plan for Ports and Goods Movement, available at http://www.arb.ca.gov/planning/gmerp/march21plan/appendix_a.pdf

Table F11-3
Total Health Impacts Associated with Emissions Related to Possible Biorefineries
and Transportation of Imported Ethanol and Biodiesel in Year 2020^a
Benefits of Advanced Vehicles Included

Endpoint	Pollutant	# of Fewer Cases 95% C.I. (Lower Bound)	# of Fewer Cases (Mean)	# of Fewer Cases 95% C.I. (Upper Bound)
Premature Death	PM	-25	-79	-150
	NOx	-11	-34	-62
	<i>Total</i>	-35	-110	-210
Hospital admissions (Respiratory)	PM	-4	-9	-14
	NOx	-2	-4	-6
	<i>Total</i>	-6	-13	-20
Hospital admissions (Cardiovascular)	PM	-11	-18	-25
	NOx	-5	-8	-11
	<i>Total</i>	-16	-25	-36
Asthma & Lower Respiratory Symptoms	PM	-510	-1,300	-2,100
	NOx	-230	-580	-900
	<i>Total</i>	-740	-1,900	-3,000
Acute Bronchitis	PM	0	-110	-240
	NOx	0	-46	-94
	<i>Total</i>	0	-160	-330
Work Loss Days	PM	-7,100	-8,300	-9,600
	NOx	-3,200	-3,800	-4,300
	<i>Total</i>	-10,000	-12,000	-14,000
Minor Restricted Activity Days	PM	-40,000	-49,000	-57,000
	NOx	-18,000	-22,000	-26,000
	<i>Total</i>	-57,000	-70,000	-83,000

^a Health effects from primary and secondary PM are labeled PM and NOx, respectively. The sum of PM and NOx impacts may not equal the total given due to rounding.

3. Programmatic Overlap between LCFS and RFS2

Congress adopted a renewable fuels standard (RFS) in 2005 and strengthened it (RFS2) in December 2007 as part of the Energy Independence and Security Act of 2007 (EISA). The RFS2 contains, among other provisions, increasing volumes of biofuels every year, up to a required volume of 36 billion gallons by 2022. Of the 36 billion gallons, 16 billion gallons must be advanced biofuels from cellulosic sources. Successful implementation of the RFS2 would result in significant quantities of low carbon intensity biofuels that could be used toward compliance with California's LCFS.

Table F11-4 shows the volume of ethanol estimated to be used in California in 2020 under the four LCFS scenarios.

Table F11-4
Volumes of Ethanol by Source and Type in California in 2020 for Each LCFS Scenario (Bgal)

Ethanol Type	Estimated CA Capacity	Calculated CA Share RFS2	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
			CA	other	CA	other	CA	other	CA	other
Corn	0.3	1.70	0.3	0.0	0.3	0.0	0.3	0	0.3	0.0
Cellulosic	0.9	1.19	0.9	0.39	0.9	0.34	0.9	0.2	0.8	0.0
Adv. Renew.			0.0	1.29	0.0	1.24	0.0	1.1	0.0	0.8
Sugar-cane			0.0	0.0	0.0	0.30	0.0	0.3	0.0	0.3
Subtotal			1.2	1.7	1.2	1.9	1.2	1.6	1.1	1.1
Total	1.2	2.9	2.9		3.1		2.8		2.2	

LCFS Scenario 1: Increasing volumes of Federal New Renewable Biofuels (ethanol) through 2015, then gradual decline of higher CI crop-based biofuels through 2020 as advanced renewable ethanol fuels become available. Conventional corn ethanol gradually decreases to zero in 2017, but lower intensity corn ethanol remains. There would be gradual increases in the number of FFVs using E85. The number of advanced technology vehicles (BEV, PHEV, FCVs) using electricity or hydrogen as a fuel increases to about 560,000 by 2020. This number is consistent with the penetration schedule in the 2008 ARB ZEV regulation.

LCFS Scenario 2: Similar to Scenario 1 except that a wider mix for cellulosic ethanol, advanced renewable ethanol, and sugarcane ethanol is used.

LCFS Scenario 3: Similar to Scenario 2 except that the number of advanced technology vehicles is increased from 560,000 vehicles to 1 million vehicles in 2020. In turn, the number of FFVs using E85 in 2020 and the amount of cellulosic ethanol, advanced renewable ethanol, and sugarcane ethanol are reduced.

LCFS Scenario 4: Similar to Scenario 3 except the number of advanced technology vehicles is increased to 2 million vehicles in 2020 and biofuel amounts are reduced.

As shown in Table F11-4, California's approximate population weighted share of ethanol due to RFS2 is 2.9 billion gallons in 2020. This volume is equal or greater than the volume required in three of the four LCFS scenarios. Therefore, it is reasonable to project that potential health impacts due to producing and importing ethanol in California would also potentially occur under the federal RFS2 program.

4. Primary Diesel PM

The estimation of premature death and other health impacts from PM exposure used by ARB staff is based on a peer-reviewed methodology developed by the U.S. EPA for their risk assessments.^{31,32,33} This methodology is regularly updated by ARB staff as new epidemiological studies and other related studies are published that are relevant to California's health impacts analysis. The methodology uses concentration-response functions which describe the relation between ambient PM_{2.5} concentration and premature death and illness. The selection of the concentration-response functions was based on the latest epidemiologic literature, as described in Emission Reduction Plan for Ports and Goods Movement in California³⁴ and Methodology for Estimating the Premature Deaths Associated with Long-term Exposure to Fine Airborne Particulate Matter in California.³⁵ The central estimate of the relative risk of premature death used in this assessment is 10 percent increase risk per 10 $\mu\text{g}/\text{m}^3$ increase in PM_{2.5} exposure, with a confidence interval of 3 percent - 20 percent⁸).

This analysis used a "tons per incident" approach to estimate the health impacts associated with emissions from possible biorefineries. These tons-per-incident factors were developed for estimating health impacts associated with changes in diesel PM exposures. The following is an example of how the approach was used to estimate the effect of PM_{2.5} on mortality. Using estimated diesel PM concentration for year 2005 (1.6 $\mu\text{g}/\text{m}^3$) and the concentration-response function for mortality⁸, we estimate that primary diesel PM exposure can be associated with a mean estimate of 3,500 premature deaths in year 2005 in California. The diesel PM_{2.5} emissions for year 2005 were 37,800 tons. Using this information, we estimate that for a reduction of 10.8 tons diesel PM_{2.5} emissions per year, one fewer premature death would result. This factor is derived by dividing 37,800 tons of diesel PM by 3,500 deaths.

Staff developed air basin-specific factors to estimate health impacts, such as hospitalizations and asthma symptoms, from PM_{2.5} exposure. These basin-specific factors were developed using basin-specific diesel PM concentrations and emissions for the year 2005 and the relevant health studies. The basin-specific factors were applied

³¹ U.S. EPA, 2004. United States Environmental Protection Agency. May, 2004. Final Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines. EPA-420-R-04-007. Office of Transportation and Air Quality. <http://www.epa.gov/otaq/regs/nonroad/equip-hd/2004fr.htm#ria>

³² U.S. EPA, 1999. United States Environmental Protection Agency. November 1999, *The Benefits and Costs of the Clean Air Act 1990 to 2010*. EPA-410-R-99-001
<http://www.epa.gov/air/sect812/copy99.html>

³³ U.S. EPA, 2005. Clean Air Interstate Rule: Regulatory Impact Analysis. March 2005:
<http://www.epa.gov/interstateairquality/pdfs/finaltech08.pdf>

³⁴ CARB, 2006. California Air Resources Board. Emission Reduction Plan for Ports and Goods Movement, available at http://www.arb.ca.gov/planning/gmerp/march21plan/appendix_a.pdf

³⁵ CARB, 2008. California Air Resources Board. Methodology for Estimating the Premature Deaths Associated with Long-term Exposures to Fine Airborne Particulate Matter in California, available at <http://www.arb.ca.gov/research/health/pm-mort/pm-mort.htm>.

to each air basin to estimate health impacts. Estimates of health impacts, such as hospitalizations and asthma symptoms, were calculated using basin-specific factors developed from relevant health studies. Details on the methodology used to calculate these estimates can be found in Appendix A of the Emission Reduction Plan for Ports and Goods Movement in California.⁹

5. Secondary Diesel PM

In addition to directly emitted PM, transportation emissions associated with possible biorefineries contain NO_x, which is a precursor to nitrates, a secondary diesel-related PM formed in the atmosphere that can lead to additional health impacts beyond those associated with directly emitted PM_{2.5}. To quantify such impacts, staff developed population-weighted nitrate concentrations for each air basin using data not only from the statewide routine monitoring network, which was used in Lloyd and Cackette¹⁰, but also from special monitoring programs such as IMPROVE and Children's Health Study (CHS) in years 2004, 2005 and 2006. The IMPROVE network provided additional information in the rural areas, while the CHS added more data to southern California. Staff calculated the health impacts resulting from the three-year average exposure to these concentrations of nitrate PM_{2.5} and then associated the impacts with the basin-specific NO_x emissions from diesel sources to develop basin-specific factors (tons per incident). The basin-specific factors and emissions were applied to each air basin to estimate health impacts. Using an approach similar to that used for primary diesel PM and adjusting for population changes between 2020 and 2005, staff estimates that the 2,000 tons of NO_x emissions related to possible biorefineries in year 2020 are associated with an estimated 17 premature deaths (6 – 32, 95% CI). Other health effects were also estimated as outlined above.

6. Assumptions and Limitations of Health Impacts Assessment

There are a number of uncertainties involved in quantitatively estimating the health impacts associated with exposure to outdoor air pollution. They include the selection and applicability of the concentration-response (C-R) functions, the exposure assessment, and the baseline incidence rates. These are briefly described below.

- A primary uncertainty is the choice of the specific studies and the associated C-R functions used for quantification. Epidemiological studies used in this report have undergone extensive peer review and include sophisticated statistical models that account for the confounding effects of other pollutants, meteorology, and individual level risk factors. While there may be questions on whether C-R functions from the epidemiological studies are applicable to California, studies have shown that the mortality effects of PM in California are

⁹ CARB, 2006. California Air Resources Board. Emission Reduction Plan for Ports and Goods Movement, available at http://www.arb.ca.gov/planning/gmerp/march21plan/appendix_a.pdf

¹⁰ Lloyd and Cackette. 2001. Lloyd, A.C.; Cackette, T.A.; Diesel Engines: Environmental Impact and Control; J Air Waste Manage. Assoc. 2001, 51: 809- 847.
[http://www.arb.ca.gov/research/seminars/lloyd/AWMA2001/JAWMADieselCritical Review.pdf](http://www.arb.ca.gov/research/seminars/lloyd/AWMA2001/JAWMADieselCritical%20Review.pdf)

fairly consistent with those found in other locations in the U.S.^{11,12,13,14} The C-R function for PM2.5-related mortality used in this report was based on a review of all relevant scientific literature and a thorough consideration of each study's strengths and limitations. In addition, it was approved by our advisors and independent peer reviewers.¹⁵

- Only emissions from truck and rail transport of feedstock and biofuel were included in the health impact calculation. There are significant emissions from the biorefineries themselves. Biorefinery emissions were not included in the health impact calculation because increased local emissions from biorefineries are expected to be offset by decreased emissions within the air basin.
- In this analysis, ARB staff assumed diesel PM is as toxic as ambient PM2.5. The basis of this assumption is the animal toxicology literature on the health impacts of constituents of diesel exhaust PM leads to the conclusion that diesel exhaust PM is at least as toxic as the general ambient PM mixture.
- This report estimated health impacts due to transport emissions associated with possible biorefineries. The methodology applies a “tons per incident” factor to estimate the number of health effects avoided due to reductions in PM2.5 and assumes the emissions are evenly distributed within the air basin.
- ARB staff assumed the baseline incidence rate for each health endpoint was uniform across each county. This assumption is consistent with methods used by the U.S. EPA for its regulatory impact assessment, and the incidence rates match those used by U.S. EPA.
- Although the analysis illustrates that PM2.5 exposure would result in health impacts to people living in California, we did not provide estimates for all endpoints for which there are C-R functions available. Health effects such as myocardial infarction (heart attack), chronic bronchitis, and onset of asthma were not quantified due to the potential overlap with the quantified effects such as lower respiratory symptoms and hospitalizations. In addition, estimates of the effects of PM2.5 on low birth weight and reduced lung function growth in

¹¹ Dominici et al. 2005. Revised analyses of the National Morbidity, Mortality, and Air Pollution Study: mortality among residents of 90 cities. *J Toxicol Environ Health A*. Vol. 68(13-14):1071-92.

¹² Franklin et al. 2007. Association between PM2.5 and all-cause and specific-cause mortality in 27 communities. *J Expo Sci Environ Epidemiol*. Vol. 17:279-287.

¹³ Jerrett, M.; Burnett, R.T.; Ma, R.; Pope, C.A., III; Krewski, D.; Newbold, K.B.; Thurston, G.; Shi, Y.; Finkelstein, N.; Calle, E.E.; Thun, M.J. Spatial Analysis of Air Pollution and Mortality in Los Angeles; *Epidemiol.* (2005), 16, 727-736.

¹⁴ Pope CA 3rd, Burnett RT, Thun MJ, Calle EE, Krewski D, Ito K, Thurston GD. 2002. Lung cancer, cardiopulmonary mortality, and long-term exposure to fine particulate air pollution. *Journal of the American Medical Association*. Vol. 287 (9): 1132-41.

¹⁵ CARB, 2008. California Air Resources Board. Methodology for Estimating the Premature Deaths Associated with Long-term Exposures to Fine Airborne Particulate Matter in California, available at <http://www.arb.ca.gov/research/health/pm-mort/pm-mort.htm>.

children are not presented. While these endpoints are significant in an assessment of the public health impacts of diesel exhaust emissions, there are currently few published investigations on these topics, and the results of the available studies are not entirely consistent.¹⁶ In summary, because only a subset of the total number of health outcomes is considered here, the estimates may be an underestimate of the total public health impact of PM exposure.

B. Economic Valuation of Health Impacts

This section describes the methodology for monetizing the value of avoiding adverse health impacts.

The U.S. EPA has established \$4.8 million in 1990 dollars at the 1990 income level as the mean value of avoiding one premature death.¹⁷ This value is the mean estimate from five contingent valuation studies and 17 wage-risk studies. Contingent valuation and wage-risk studies examine the willingness to pay (or accept payment) for a minor decrease (or increase) in the risk of premature death. For example, if individuals are willing to pay \$800 to reduce their risk of mortality by 1/10,000, then collectively they are willing to pay \$8 million to avoid one death. This is also known as the “value of a statistical life” or VSL.¹⁸

As real income increases, people are willing to pay more to prevent premature death. U.S. EPA adjusts the 1990 value of avoiding a premature death by a factor of 1.201 to account for real income growth from 1990 through 2020.^{19,20} We also updated the value to 2008 dollars. After these adjustments, the value of avoiding one premature death is \$9.3 million in 2009, and \$10 million in 2020, all expressed in 2008 dollars. The U.S. EPA also uses the willingness-to-pay (WTP) methodology for some non-fatal health endpoints, including lower respiratory symptoms, acute bronchitis and minor restricted

¹⁶ CARB, 2006. California Air Resources Board. Emission Reduction Plan for Ports and Goods Movement, available at http://www.arb.ca.gov/planning/gmerp/march21plan/appendix_a.pdf

¹⁷ U.S. EPA, 1999. United States Environmental Protection Agency. November 1999, *The Benefits and Costs of the Clean Air Act 1990 to 2010*. EPA-410-R-99-001
<http://www.epa.gov/air/sect812/copy99.html>

¹⁸ Some recent U.S. EPA regulatory impact analyses, (U.S. EPA 2004, 2005), apply a different VSL estimate (\$5.5 million in 1999 dollars, with a 95 percent confidence interval between \$1 million and \$10 million). This alternative value has not been endorsed by the Environmental Economics Advisory Committee (EEAC) of U.S. EPA’s Science Advisory Board (SAB). Until U.S. EPA’s SAB endorses another estimate, CARB staff continues to use the last VSL estimate endorsed by the SAB, i.e., \$4.8 million in 1990 dollars.

¹⁹ U.S. EPA’s real income growth adjustment factor for premature death incorporates an elasticity estimate of 0.4. CARB applies an elasticity estimate of 0.5 because both U.S. EPA, (U.S. EPA 2004), and a review of published estimates (Viscusi and Aldy, 2004) indicate that a value of 0.4 underestimates elasticity.

²⁰ U.S. EPA’s real income growth adjustment factor for premature death incorporates an elasticity estimate of 0.4. CARB applies an elasticity estimate of 0.5 because both U.S. EPA, (U.S. EPA 2004), and a review of published estimates (Viscusi and Aldy, 2004) indicate that a value of 0.4 underestimates elasticity.

activity days. WTP values for these minor illnesses are also adjusted for anticipated income growth through 2020, although at a lower rate (about 0.2 percent per year in lieu of 0.6 percent per year).

For work-loss days, the U.S. EPA uses an estimate of an individual's lost wages²¹, which ARB adjusts for projected real income growth, at a rate of approximately 1.5 percent per year.

"The Economic Value of Respiratory and Cardiovascular Hospitalizations"²² calculated the cost of both respiratory and cardiovascular hospital admissions in California as the cost of illness (COI) plus associated costs such as loss of time for work, recreation and household production. When adjusting these COI values for inflation, ARB uses the Consumer Price Index (CPI) for medical care rather than the CPI for all items.

Table F11-5 lists the valuation of avoiding various health effects, compiled from ARB and U.S. EPA publications, updated to 2008 dollars. The valuations based on WTP, as well as those based on wages, are adjusted for anticipated growth in real income.

ARB staff estimates the statewide health impacts of the emissions associated with this regulation in year 2020 are approximately \$150 million using a 3 percent discount rate or \$100 million using a 7 percent discount rate²³. A large proportion of the monetized health impacts results from premature death. The estimated impacts from morbidity are approximately \$1.1 million with a 3 percent discount rate and \$750 thousand with a 7 percent discount rate. Approximately 85 percent of the benefits are associated with reduced PM from NOx emissions, and the remaining 15 percent from direct PM emissions.

²¹ U.S. EPA, 2004. United States Environmental Protection Agency. May, 2004. Final Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines. EPA-420-R-04-007. Office of Transportation and Air Quality. <http://www.epa.gov/otaq/regs/nonroad/equip-hd/2004fr.htm#ria>

²² CARB, 2003. Air Resources Board. May 2003. Final Research Report: The Economic Value of Respiratory and Cardiovascular Hospitalizations. <ftp://ftp.arb.ca.gov/carbis/research/apr/past/99-329.pdf>

²³ CARB follows U.S. EPA practice in reporting results using both 3 percent and 7 percent discount rates.

Table F11-5
Undiscounted Unit Values for Health Effects
(at various income levels in 2008 dollars)^a

Health Endpoint	2009	2010	2020	Footnotes
Mortality				
Premature death (\$ million)	9.3	9.4	10	24 25 26 , ,
Hospital Admissions				
Cardiovascular (\$ thousands)	46	46	52	27
Respiratory (\$ thousands)	38	38	43	27
Minor Illnesses				
Acute Bronchitis	453	454	467	24
Lower Respiratory Symptoms	20	20	21	24
Work loss day	202	206	250	28
Minor restricted activity day (MRAD)	64	64	66	24

^aThe value for premature death is adjusted for projected real income growth, net of 0.5 elasticity. Wage-based values (Work Loss Days) are adjusted for projected real income growth, as are WTP-derived values (Lower Respiratory Symptoms, Acute Bronchitis, and MRADs). Health endpoint values based on cost-of-illness (Cardiovascular and Respiratory Hospitalizations) are adjusted for the amount by which projected CPI for Medical Care (hospitalization) exceeds all-item CPI.

²⁴ U.S. EPA, 2004. United States Environmental Protection Agency. May, 2004. Final Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines. EPA-420-R-04-007. Office of Transportation and Air Quality. <http://www.epa.gov/otaq/regs/nonroad/equip-hd/2004fr.htm#ria>

²⁵ U.S. EPA, 1999. United States Environmental Protection Agency. November 1999, *The Benefits and Costs of the Clean Air Act 1990 to 2010*. EPA-410-R-99-001
<http://www.epa.gov/air/sect812/copy99.html>

²⁶ U.S. EPA, 2000. United States Environmental Protection Agency. September 2000, *Guidelines for Preparing Economic Analyses*. EPA240-R-00-003

²⁷ CARB, 2003. Air Resources Board. May 2003. Final Research Report: The Economic Value of Respiratory and Cardiovascular Hospitalizations. <ftp://ftp.arb.ca.gov/carbis/research/apr/past/99-329.pdf>

²⁸ US DOL-BLS, 2009. United States Department of Labor, Bureau of Labor Statistics. 2007 California average weekly wage data, BLS Data Series ID ENUO600040010. <http://www.bls.gov/cew/#databases>

C. Conclusion

For this report, ARB staff quantified seven non-cancer health impacts associated with the transportation emissions from possible new biorefineries. This analysis shows that the statewide health impacts of these emissions in year 2020 are approximately 20 premature deaths, 2 hospital admissions due to respiratory causes, 5 hospital admissions due to cardiovascular causes, 290 cases of asthma-related and other lower respiratory symptoms, 24 cases of acute bronchitis, 1,900 work loss days, and 11,000 minor restricted activity days. The uncertainty behind each estimated impact ranges from about 15 percent to 75 percent for most endpoints. The estimated statewide impacts in year 2020 associated with health effects is 100 million using a 7 percent discount rate or \$150 million using a 3 percent discount rate.

Health effects and valuations are estimated to be a result of the increased biorefinery and import transportation emissions only and might be expected if there were no emissions benefits resulting from the proposed LCFS. However, a reduction in criteria pollutant emissions including NO_x and PM_{2.5} is expected as a result of increased penetration of advanced vehicles and CNG vehicles. These health benefits are expected to be greater than the expected health impacts of biorefinery and import transportation emissions.

The federal RFS2 program requires ethanol volumes to be used in California that under most LCFS scenarios are greater than the ethanol volume expected under the RFS alone. Therefore, it is reasonable to project that health impacts due to producing and importing ethanol in California will also potentially occur under the federal RFS2 program.

ATTACHMENT C

List of Acronyms

This list contains all of the acronyms and their meanings, with the exception of the ones generated to identify the commenters.

Acronym	Definition
AAM	Alliance of Automobile Manufacturers
AB32	Assembly Bill 32
AFCI	Advanced Fuel Cycle Initiative
APA	Administrative Procedure Act
AQMD	Air Quality Management District
ARB	Air Resources Board
ARP	Acreage Reduction Programs
ASTM	ASTM International - American Society for Testing and Materials
B#	Biodiesel percentage in the petroleum fuel
BACT	Best Available Control Technology
BESS	A Model for Life-Cycle Energy & Emissions Analysis of
BEV	Corn-Ethanol Biofuel Production Systems
BOD	Biological Oxygen Demand
BTL	Biomass to Liquids
CaCO	Calcium Carbonate - Limestone
CA-GREET	California Input for The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model
CARB	California Air Resources Board
CARBOB	California Reformulated Gasoline Blend Stock of Oxygenate Blending
CaRFG	California Reformulated Gasoline
CBG	Cleaner-Burning Gasoline
CDFA	California Department of Food and Agriculture
CDM	Clean Development Mechanism
CEC	California Energy Commission
CEPC	California Environmental Policy Council
CEQA	California Environmental Quality Act
CFR	California Code of Regulations
CFR	Code of Federal Regulations
CGE	Computable General Equilibrium
CI	Carbon Intensity
CIWMB	California Intergrated Waste Management Board
CNG	Compressed Natural Gas
CPUC	California Public Utilities Commission
CTL	Coal to Liquids
DDGS	Dried Distiller's Grain with Solubles
DG	Distiller Grain

Acronym	Definition
DGS	Distiller's Grain with Solubles
DMS	CDFA Division of Measurement Standards
DOE	Department of Energy
DOGGR	Department of Oil, Gas, and Geothermal Resources
DTSC	Department of Toxic Substance Control
E#	Ethanol percentage in the petroleum fuel
EAM	Early Action Measure
EBAMM	ERG Biofuel Analysis Meta-Model
	Environmental Revenue Dynamic
EDRAM	Assessment Model
EEA	European Environment Agency
EER	Energy Economy Ratio
EIA	Energy Information Administration
EIR	Environmental Impact Report
EISA	Energy Independence and Security Act
EJ	Environmental Justice
EMBRAPA	Empresa Brasileira de Pesquisa Agropecuária
EMFAC	Emission FACtors Model
EO	Executive Office
ETBE	Ethyl tert-butyl ether
EtOH	Ethanol
FAHC	Fatty Acid to Hydrocarbon
FAME	Fatty Acid Methyl Ester
FAO	Food and Agriculture Organization
FAPRI	Food and Agricultural Policy Research Institute
FASOM	Forestry and Agricultural Sector Optimization Model
FCV	Fuel Cell Vehicle
FFCCF	Full Fuel Cycle Carbon Footprint
FFV	Flex Fuel Vehicle
FIAN	FoodFirst Information and Action Network
FSOR	Final Statement of Reasons
FT	Fischer-Tropsch
FWP	Fuel Warming Potential
gCO ₂ E/MJ	Grams of Carbon Dioxide Equivalent per Mega Joule
gge	Gasoline Gallon Equivalents
GHG	Greenhouse Gas
GHG	Greenhouse
GPS	Global Positioning System
GQI	
	The Greenhouse Gases, Regulated Emissions, and Energy
GREET	Use in Transportation (GREET) Model
GTAP	Global Trade Analysis Project
GTL	Gas to Liquids
GVRW	Gross Vehicle Weight Rating
GWh	Giga Watt Hours

Acronym	Definition
GWI	Global Warming Impact
HCHO	Formaldehyde
HCICO	high carbon-intensity crude oils
HDV	Heavy Duty Vehicle
HFC	Hydrofluoro Carbons
HRA	Health Risk Assessment
HREV	Human Rights Everywhere
HRJ	Hydrotreated Renewable Jet fuel
HSC	Health and Safety Code
ICEV	Internal Combustion Engine Vehicle
IEA	International Energy Agency (IEA)
IEPR	Integrated Energy Policy Report
IEPR	Integrated Energy Policy Report
IFPRI	International Food Policy Research Institute
IFWG	Interagency Forrest Workgroup
ILUC	International Land Use Change
IPCC	International Policy on Climate Change
IPH	Industrial Process Heat
ISOR	Initial Statement of Reasons
LCA	Life Cycle Assessment
LCFS	Low Carbon Fuel Standard
LCS	Low Carbon Standard
LDV	Light Duty Vehicle
LFG	Landfill Gas
LNG	Liquid Natural Gas
LPG	Liquid Petroleum Gas
LRT	LCFS Reporting Tool
LUC	Land Use Change
MAGICC	Model to Assess Greenhouse Gas Induced Climate Change
MDV	Medium Duty Vehicle
MGY	Megagallons per Year
MMT	Mega Metric Tons
MRAD	Minor restricted activity day
MSW	Municipal Solid Waste
MT	Metric Tons
MTBE	Methyl tert-butyl ether (
MVF	Motor Vehicle Fuel
NASS-USDA	National Agricultural Statistics Service Information-USDA
NDEQ	Nebraska Department of Environmental Quality
NEPA	National Environmental Policy Act
NIR	Near Infrared
NMOG	Non-Methane Organic Gas
NOx	Nitron Oxide Emissions
NPAH	Nitrated Polycyclic Aromatic Hydrocarbons
NPDES	National Pollution Discharge Elimination System

Acronym	Definition
NPRM	Notice for Proposed Rulemaking
NPV	Net Present Value
NRDC	Natural Resources Defense Council
NREL	National Renewable Energy Laboratory
NRER	Net Renewable Energy Ratio
NREV	Net Renewable Energy Value
O.E.C.D.	Organization for Economic Cooperation and Development
OAL	Office of Administrative Law
ORNL	Oak Ridge National Laboratory
PADD	Petroleum Administration for Defense Districts
PAH	Polycyclic Aromatic Hydrocarbons
PCDO	poly-chlorinated dibenzodioxins
PCFO	poly-chlorinated dibenzofurans
PHEV	Plug-in Hybrid Vehicles
PIIRA	Petroleum Industry Information Reporting Act
PLCFS	Proposed Low Carbon Fuel Standard
PTD	Product Transfer Documents
PY	Person Year
PZEV	Partial Zero Emissions Vehicle
RF	Radiative Forcing
RFA	Renewable Fuels Association
RFS	Renewable Fuel Standard
RINs	Renewable Identification Numbers
RPS	Renewable Portfolio Standard
RSPO	Roundtable on Sustainable Palm Oil
RTRS	Roundtable for Responsible Soy
RVP	Reid Vapor Pressure
SAE	Society of Automotive Engineers
SCR	Selective Catalytic Reduction
SDSU	South Dakota State University
SWRCB	State Water Resource Control Board
TEOR	Thermally Enhanced Oil Recovery
TIAX	Consulting Firm
TRS	Total Recoverable Sugars
TTW	Tank to Wheels
UCB	University of California, Berkeley
UCD	University of California, Davis
UCS	Union of Concerned Scientists
UIC	Underground Injection Control
ULEV	Ultra Low Emission Vehicle
ULSD	Ultra Low Sulfur Diesel
	Renewable Diesel II (proprietary processing to make renewable diesel)
UOP-HDO	
USDA	United States Department of Agriculture
USDA-FAS	USDA Foreign Agricultural Service

Acronym	Definition
USEPA	United States Environmental Protection Agency
UST	Underground Storage Tank
WCI	Western Climate Initiative
WDGS	Wet Distiller's Grain with Solubles
WGA	Western Governor's Association
WSPA	Western States Petroleum Association
WTE	Waste to Energy
WTP	Willingness to Pay
WTT	Well to Tank
WTW	Well to Wheels
WWTP	Waste Water Treatment Plant
XSD	XML Schema Document
ZEV	Zero Emission Vehicle