Chevron

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[Submitted Electronically]

Clerk of the Board
Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Low Carbon Fuel Standard Re-Adoption

Dear Madam or Sir:

Chevron appreciates the opportunity to review and comment on the referenced re-adoption proposal.

Chevron is a major refiner and marketer of petroleum products in the state of California and a regulated party under the Low Carbon Fuel Standard (LCFS). We are a member of the Western States Petroleum Association (WSPA) and we support the comments submitted by WSPA in response to this proposed rulemaking. We are providing our separate comments below that highlight the issues of greatest importance to Chevron.

If you have any questions regarding our comments, please contact Nick Economides (925-842-5054) or Rick Powell (832-854-6541).

Thank you for providing this opportunity for Chevron to comment on the re-adoption.

Kind Regards,

Rick Powell
General Manager
Fuels & Product Strategy

# Comments of Chevron

**Re-Adoption of the California Low Carbon Fuel Standard:**
**Initial Statement of Reasons**

February 17, 2015

Chevron appreciates the opportunity to submit written comments for the record on the above proposed rulemaking. Chevron is a California-based company engaged in oil and gas exploration, petroleum refining and petroleum product marketing. We are a regulated party under the Low Carbon Fuel Standard (LCFS). We are a member of the Western States Petroleum Association (WSPA) and we support the comments submitted by WSPA in response to this proposed rulemaking.

We understand that at the February 19-20 Air Resources Board (ARB) hearing, the Board will consider re-adoption of the Low Carbon Fuel Standard (LCFS) Regulation as well as adoption of the Alternative Diesel Fuel (ADF) regulation. Staff has jointly progressed these two rulemakings and considers them intimately connected as a joint regulatory action "package" to address requirements emanating from the July 15, 2013 State of California Court of Appeal, Fifth Appellate District (Court) opinion in POET LLC *v*. California Air Resources Board (2013) 218 Cal.App.4th 661. The judge's opinion was that ARB did not adequately address biodiesel NOx emissions that could potentially result from LCFS implementation. The ADF regulation represents staff's proposed solution to address California Environmental Quality Act deficiencies associated with biodiesel NOx impacts. Chevron's comments on the ADF proposed rule have been incorporated in those submitted by the Western States Petroleum Association (WSPA), of which Chevron is a member. Our comments below are exclusively devoted to the LCFS rulemaking.

Chevron has worked with ARB over the past few months on the proposed LCFS re-adoption and participated in the series of workshops held by staff on individual segments of the proposed regulations. Chevron was also a member of ARB's LCFS Advisory Panel and participated in that group's meetings in 2014. Chevron has provided feedback to ARB through WSPA throughout the rule development process. Finally, Chevron has met with staff individually before and after the issuance of staff's Statement of Reasons document to outline our concerns regarding the proposed revisions to the program. We appreciate staff's openness in receiving our input on the large number of issues and considerations involved in this rulemaking and look forward to working with staff on additional refinement of the details of the proposed regulation in the coming months. We are prepared to discuss our comments further with ARB staff, if needed.

## Summary

Halfway through the compliance decade (2010-2020), the LCFS program is falling short of meeting its originally envisioned targets and should be adjusted to more accurately reflect the real-world rate of development and market penetration of advanced low carbon intensity fuels. The primary reason is that technology in the cellulosic biofuel space has not emerged as ARB had anticipated. Chevron has first-hand knowledge of this; we embarked on an aggressive program to evaluate and develop promising new technologies and have been largely unsuccessful in this costly endeavor.

Staff implicitly recognizes that the original program targets are overly aggressive; they propose to revise the interim year (2016-2019) CI reduction targets downward in the proposed rule re-adoption. However, staff maintains that the 10% reduction target remains achievable and that "the program is working as intended." Staff's adjustment of the interim year targets, while welcomed, does not go far enough toward establishing the sustainability of the program moving forward. Moreover, claiming that the program's original CI reduction target can be met through the use of massive quantities of accumulated credits in the early years (when over-compliance may be possible), masks the true nature of the challenge the program faces as we head to 2020.

In doing so, staff is not informing California policy makers of the need for immediate adjustment of the program's targets, choosing instead to delay action that will only yield a more severe crisis that must be addressed the next time program progress is reviewed. This decision further propagates the climate of uncertainty that this program has been shrouded in since its inception. It denies all stakeholders the opportunity to formulate concrete compliance strategies and turn their attention to their execution. Instead, affected stakeholders recognize that the program targets will need to be revised once again at some time in the near future. Thus, they remain "on hold" awaiting such revisions, with the delay further casting the program's 2020 goals in doubt. Chevron strongly recommends that staff adopt reasonable, achievable and sustainable CI reduction targets for all years up to and including 2020 as part of the LCFS' re-adoption and has provided staff with its estimates of what such a compliance schedule entails.

Chevron defines program "success" as the achievement of sustainable CI reductions, i.e., targets that can be met largely by the CI reductions generated during the individual compliance year with minimal reliance on an accumulated credit bank to accommodate the expected normal market fluctuations during the year. In that context, Chevron believes that the program's success depends on a dual-pronged strategy involving the setting of reasonable CI reduction targets (the "compliance curve") and maintaining close oversight of the program as it moves forward to ensure it is meeting its forecasted targets. To this end, Chevron recommends that ARB build mandatory biennial comprehensive LCFS program reviews into the re-adoption proposal, with the first one to be completed no later than 1/1/2017.

While we recognize that the actions emanating from such interim LCFS program reviews cannot be predetermined, we expect ARB to consider concrete and specific key indicators (e.g., predicted vs. actual low-CI fuel penetration, predicted vs. actual LCFS credit balances, predicted vs. actual credit prices, overall credit market liquidity, differential of CA gasoline and diesel market prices versus the rest of the nation) as part of these reviews. Chevron also expects staff to include adjustment of the program's outer year targets in the scope of the interim reviews, should evidence of significant and systemic over- or underperformance versus the program targets be established.

Chevron is opposed to the Credit Clearance Market (CCM) proposed by staff as a cost control mechanism in the LCFS re-adoption rule. While we appreciate staff's intent in controlling costs to the consumer during short-lived periods when compliance obligations cannot be met and credit availability declines, Chevron believes that the proposed CCM mechanism has serious flaws and could very well result in unintended negative consequences. More specifically, CCM:

- Does not stipulate a mechanism for retiring deficits, if multi-year market shortages persist leaving the regulated community with the prospect of ever-increasing deficit accruals.

- May drive credit costs up, if credits are withheld from the regular market to get a higher CCM price at the end of the year.

- Provides no liability protection against invalid credits secured through the year-end CCM.

- Offers no connection between CCM outcome, program off-ramps, and future CI reduction targets.

- Offers refiners no flexibility to voluntarily participate and eliminates their ability to carry-over credits if they do not.

For these reasons, Chevron believes that staff should abandon the proposed CCM and rely instead on the combination of setting achievable targets and frequent interim program reviews outlined earlier. If staff insists on including a cost containment mechanism in the LCFS, Chevron recommends adoption of a simpler program analogous to that employed by EPA in the Renewable Fuels Standard.

Chevron believes that staff's forecast of potential CI reductions (and associated targets) in the 2018-2020 time frame are ambitious and unsustainable. Staff's own estimates show that only 7% of the 10% 2020 CI reduction target is sustainable, with the balance (3% CI reduction) attributable to using 7 million metric tons of $CO_2e$ ($MMTCO_2e$) from the forecasted credit bank. Chevron notes that:

- Staff's assumptions on the potential LCFS credit buildup (through 2016) and drawdown (in 2017-2020) are unrealistic. The credit bank, since program inception, stood at slightly under 4 MMT at the end of the 3rd quarter of 2014 (the most recent available actual data). Staff assumes that it will rise to approximately 9MMT by the end of 2015 but offers little in terms of factual support for this aspirational view other than program re-adoption will provide the necessary program certainty for credit generation to begin in earnest.

Chevron's view is that the credit bank will likely build at a much slower pace and be exhausted by 2020, as individual year deficits materialize as early as 2017.

- Chevron's projections of relative contributions from most low-CI reduction fuels (e.g., ethanol, biodiesel) and other credit sources (e.g., electric vehicles) over the 2015 to 2020 period are approximately consistent with staff's. However, Chevron disagrees with key staff assumptions of the rate of growth (and associated contribution to meeting LCFS targets) of renewable diesel (RD) and renewable natural gas/biogas (RNG):

  - While renewable diesel is one of the more promising available low carbon intensity fuels for LCFS compliance, ARB's supply projections are optimistic and overly reliant on announced projects and nameplate capacities and downplay inherent feedstock availability concerns that will limit the longer term "upside" of RD. Furthermore, logistical hurdles in the short term (through 2016) involving Federal Trade Commission dispenser pump labeling regulations, superimposed on the fungible nature of the common carrier pipeline system, will be more difficult to overcome than staff assumes in projecting that RD will represent 12% of CARB diesel by 2020.

  - Staff's degree of reliance on large-scale production of RNG and diversion to motor fuel applications to generate LCFS credits is questionable. Without RFS and LCFS credit subsidies, RNG for transportation is uneconomic and, in our experience, investors are loath to take on projects where the entire rate of return is based on valuation of regulatory compliance credits. While biogas production is growing steadily, the economics are driving most new production to electricity. RNG projects typically cost twice as much as electricity projects yet offer no additional GHG emission benefits nor do they offer higher non-subsidy revenue to the producer. Furthermore, pipeline injection remains a major barrier due to its high cost, gas quality concerns, and surplus capacity availability.

- Chevron recognizes ARB's efforts to allow credit for refinery investments as an element of LCFS GHG reductions. Chevron is opposed to the concept of stationary source credits being applied to LCFS; we believe that these are covered under ARB's cap and trade program. However, since staff appears to be moving in this direction regardless of our input, we have turned our attention to ensuring the program's efficacy. We recognize that, before considering specific project applications, staff will need to establish the relative efficiency of the applicant refinery versus its peers. Staff's proposed choice of method and tools for efficiency ranking refiners in the state is inappropriate and inequitable toward larger, more efficient refiners. Moreover, the proposed thresholds and restrictions proposed by staff risk eliminating most potential projects. Chevron has conveyed its views of necessary modifications to staff; highlights of our proposed changes in the Refinery Investment Credit segment of the rule are included below:

  - The metric used to establish relative refinery efficiency should be the Complexity Weighted Barrel (CWB) as described in the detailed section of our comments.

- Refiners should be allowed to offer offsets of criteria and air toxic pollutants if their efficiency improvement projects indicate a potentially adverse impact in such emissions.
- The 0.1 gCO2e/MJ threshold is too stringent and should be revised consistent with staff's proposed minimum for Innovative Crude Production Technologies.
- Investments should not be limited to capital projects; oftentimes sizeable energy efficiency improvements are funded out of operating expense per established IRS accounting regulations**.**
- The project eligibility cutoff date should be changed to the project's startup date for any project commissioning post 1/1/2015; regardless of when initial project permit applications were filed, the project has not delivered GHG reductions until it starts up.
- The bio-feedstock 10% threshold is too restrictive, even if defined as "percent of total process unit feed." Staff should convert this threshold to a minimum absolute GHG reduction impact.

Chevron recognizes that staff is recommending no changes to the crude handling provisions in LCFS as part of the re-adoption rulemaking. Notwithstanding Chevron's concerns with crude differentiation within the LCFS, <u>Chevron supports staff's decision not to recommend conversion from the current three-year CA average crude intensity tracking system to individual refinery baseline crude CI values and agrees with the rationale offered by staff for this decision</u>. Chevron also recognizes ARB's desire to continually improve the accuracy of LCFS data inputs, and recognizes that staff's approach in the re-adoption rulemaking is consistent with that principle. However, <u>we also believe that the degree of crude differentiation built into LCFS, unfairly penalizes indigenous CA crude production and remains unnecessarily excessive and should be reduced</u>. Our reasoning is as follows:

- The fundamental reason for these provisions in the rule was to ensure that the average carbon intensity of crudes processed by California refiners did not increase over time. The available crude breakdown data for recent years (2012-1H2014) suggests that this threat has never materialized and that the CA crude average CI has remained relatively stable.
- The revised average indigenous California crude CI values included in the re-adoption package are overwhelmingly higher than corresponding values in the existing rule. Based on first half of 2014 crude volumes, the CI has increased by approximately 19% (comparing "old" vs. "new" Table 8 crude values). Our industry is effectively penalized for its attempts to maintain and increase in-state crude production even though the mix of crudes processed by CA refineries is not changing.
- The worst case scenario these provisions could potentially drive (i.e., exporting heavy California crude to maintain a constant annual average crude CI) yields no tangible greenhouse gas reduction benefits from a global standpoint.

- The ongoing staff effort to maintain and improve crude differentiation inputs and modeling tools in the LCFS is resource-intensive for ARB and equally burdensome for our industry.

In the absence of a valid GHG justification for engaging in such a complex crude differentiation and tracking scheme and in view of the potential adverse impact on indigenous California crude, we believe staff should be moving in the opposite direction than they have been following, i.e., one of simplification and streamlining. We look forward to working with staff on potential improvements to the LCFS crude differentiation provisions following the February Board Hearing.

Chevron does not view the Innovative Crude Production provisions proposed for inclusion in the LFCS re-adoption as yielding meaningful contributions for compliance by 2020 and notes that staff's illustrative compliance scenario does not include contributions from this sector. As mentioned in the Refinery Investment Credit provision discussion above, Chevron does not favor inclusion of credits from stationary sources in LCFS. Should staff choose to proceed, Chevron objects to limiting the application of carbon sequestration (CCS) to those instances where the carbon capture occurs onsite at the crude oil production facilities. CCS has the potential to generate a substantial number of credits under this provision, but many projects (and proposed projects) involve capturing carbon not at the same physical site where the crude is extracted. This restriction could seriously limit the potential for CCS to generate LCFS credits. While the capture of $CO_2$ from a steam generator or other equipment used in the oil production process may be desirable, the overall cost of doing so is prohibitive compared to capture from other large $CO_2$ emission sources.

## Detailed Comments

Following is a series of comments on the various components of ARB's LCFS re-adoption proposal. For each of the topics below, we are providing detailed comments in the subsequent sections.

- **Program Status and Proposed Compliance Targets:** Staff has adjusted the interim year CI reduction compliance targets (2016-2019) lower in the proposed re-adoption rule but has retained the original regulation's 10% reduction target for 2020. The proposed LCFS targets appear to be unsustainable, even by ARB's own analyses.
- **Low-CI Fuel Availability:** Staff's projections of Renewable Diesel use and Biogas market penetration are substantially higher than Chevron's.
- **Cost Containment Mechanism**: Staff proposes a credit clearance market that is overly complicated and predicated on the false premise that any failure to meet the LCFS CI reduction targets will be the result of a lack of credit buyers rather than a lack of credit sellers.
- **Refinery Investment Credit:** ARB proposes to allow refiners to generate credits for GHG reduction projects, but has established restrictions that are likely to prevent many potential projects from qualifying.
- **Electricity Provisions:** The proposals to allow credit generation for electric transportation usage that predates the LCFS and for estimated home vehicle charging

are inappropriate. These artificial credits would have no tie to real GHG reduction, and are inconsistent with proposed rules related to refinery credits.

- **OPGEE:** ARB's continued insistence on crude differentiation serves only to lead to inefficiency, competitive disadvantage for California crude production, and potential "crude shuffling."
- **Indirect Land Use Change:** ARB has refined the ILUC values contained in the proposed regulation based on updated data sources, as well as input from academia and the regulated community. We encourage ARB to keep this process open and transparent.
- **Low Complexity / Low Energy Use Refineries:** ARB is adding unnecessary complication by allowing those refineries who have not invested in the scale needed to meet the high demands of the California fuel market to generate credits and opt out of the state average CI calculations.
- **Innovative Crude Production:** The proposed additions and enhancements to the innovative crude technology options are encouraging, but there is room for improvement.
- **Reporting and Recordkeeping:** We appreciate ARB's efforts to improve accuracy in reporting and the added time for reconciliation with counterparties. We do not, however, agree with some of the other proposed changes.
- **Enforcement:** The proposed per-day violations for reporting errors have the potential to be unduly punitive. We recommend reducing the applicable time period to cover only the time beginning with discovery of the error. Further, there should be an affirmative defense for invalid credits analogous to the RFS.
- **Economic Impact Analysis:** While acknowledging that the LCFS will likely put upward pressure on the cost of fuel in California, ARB understates the expected economic impact by relying on an upper limit of $100/MT for credit prices.

## Current Program Status and Proposed Compliance Targets

Since its inception, the LCFS program has aspired to deliver a 10% reduction in California motor fuel carbon intensity (CI) by 2020 versus the 2010 baseline year.
As a result, Chevron engaged in an extensive program to aggressively evaluate promising emerging technologies in this space and invested considerable resources in pursuing those that we believed held the highest potential for success. Unfortunately, five years into the LCFS program, the progress envisioned in cellulosic biofuel development has not materialized, rendering the achievement of the LCFS program's original goals and targets questionable at best. Nevertheless, In the LCFS re-adoption proposal, staff holds on steadfastly to the 10% CI reduction target by 2020. In associated statements, both in California and other jurisdictions considering LCFS programs (e.g., Washington, Oregon), staff holds that "the program is working as intended,"

Half-way through the 2010-2020 compliance decade, the program is delivering approximately 2% CI reduction (versus an annual target of 1% for 2014 and 2015). Despite a nearly year-long re-examination of the program's components and targets leading up to the re-adoption Board hearing, staff is reluctant to admit that the program faces considerable challenges, even as it proposes to scale back some of the program's targets (e.g., interim-year CI reduction targets – "the compliance schedule") while leaving others (e.g., the 10% 2020 target) in place despite clear evidence that they cannot be met.

ARB's own estimates indicate that the LCFS program as proposed in the re-adoption proposal is not sustainable. Approximately 3% of 10% CI reduction shown for staff's illustrative scenario in 2020 is derived from accumulated credits (from "over-compliance" during previous years) and only 7% is actual, sustainable CI reduction obtained during the year. Annual targets remain unsustainable; staff forecasts a credit bank build up to 9 MMT at the end of 2015 to help satisfy the inherently un-sustainable reductions that the program calls for as we head toward 2020. The reality is that the credit bank stood at just under 4 MMT at the end of the third quarter of 2014 (since program inception) and the expectation it will reach 9MMT over the next 15 months is largely aspirational. ARB's view is that there will be an extraordinary increase in the rate of credit generation over this period as industry will have the benefit of "certainty" following the regulation's re-adoption.

Setting aside the issue of ARB's reliance on an unrealistic initial credit bank starting point at the start of 2016 (to meet the 10% 2020 target), Chevron does not agree that staff's projection of a 7% sustainable reduction in 2020 is accurate. The primary reasons are: staff is using overly aggressive projections in estimating the degree of market penetration of renewable biogas for motor fuel applications and the volumes of renewable diesel that will be incorporated in the CARB diesel pool. Questionable LCFS credit contributions are also forecasted from the Refinery Investment Credit segment of the re-adoption program. The reasons for Chevron's reservations in these areas are outlined further in the detailed comments on these topics.

Chevron notes the "redirection" of ARBs reliance on different sector contributions to achieve the program's CI reduction goals. There is no significant contribution expectation from advanced cellulosic biofuels that lay at the core of the original program's aggressive goals. This is not surprising given that staff's expectations for growth in that area have not materialized. Going forward, the relative contribution of such low-CI fuels is but a very small fraction of the overall program CI reduction needs. Faced with a substantial reduction in the contribution expected from advanced biofuels, ARB should have reduced LCFS program targets accordingly. We are disappointed that ARB has largely held on to the original program targets (at least for 2020) and looked to fill the cellulosic fuel CI reduction "gap" through aspirational increases in renewable biogas and renewable diesel, as well as arbitrary inclusion of LCFS credits from stationary source segments such the "Refinery Investment Credit" and "Innovative Technologies for Crude Oil Production." In Chevron's view, this "redirection," aspirational CI reduction projections, and over-reliance on banked credits in the 2016-2020 timeframe reflect the magnitude of the challenges that the program is currently facing.

Chevron continues to maintain that there is no certainty in the setting of unrealistic goals and targets that the entire regulated community views as mere placeholders that will have to be ultimately revised. In fact, this approach only serves to prolong the very climate of uncertainty, and sustain deferred action on compliance plans, investments, etc. that ARB should be seeking to promote. In the case of the re-adopted LCFS, once the credit bank status for 2015 is confirmed to be substantially lower than staff's expectations (i.e., roughly within a year's time from re-adoption), the infeasibility of the 2020 CI reduction target will be difficult to dispute and the need for revision will be even more urgent since 2020 will be only four years away at that point.

ARB's ISOR documentation is lacking in terms of detailed data to clearly support the contention that the program is still feasible. A full analysis of the available supply of low-CI fuels; the projected cost of the available fuels; the supply logistics (marine, rail, etc.) which are available to accommodate these alternative fuels; the infrastructure needed to blend, transport and dispense these fuels; the incentives which are needed for consumer acceptance; and other regulatory impediments should all be delineated.

Chevron has developed its own estimates of low-CI fuel volumes which might be available through 2020. We have shared our estimates with ARB, which has also received corresponding input from WSPA based on the work of the Boston Consulting Group (BCG). We have analyzed ARB's assumptions relating to the LCFS compliance curves and are pleased that staff's estimates have been gradually adjusted through this process to more closely reflect our own. In most areas, essential alignment has been reached between our respective viewpoints/estimates with only minor differences remaining. However, key differences remain in:

- The definition of what constitutes a sustainable program. Chevron believes that targets are sustainable if they can be met through the CI reductions accomplished during a particular compliance year with minimum reliance on credit to cover short-term shortfalls.

- The size of the credit bank on 1/1/2016 that will be available to cover future program shortfalls. Chevron's view is that the credit buildup forecasted by ARB is unsubstantiated and is unlikely to materialize.

- Chevron also forecasts that individual credit deficit years will be seen as early as 2017, requiring earlier withdrawals from the credit bank.

- As a combined result of the two previous items (lower credit bank "build" and earlier withdrawals), Chevron expects the credit bank to be essentially exhausted in the 2018 timeframe, leaving no reserves for the large credit drawn necessary to meet the 2020 10% reduction target.

- Chevron's realistic market based outlook indicates substantial differences in our projections of RNG and RD market penetration versus staff's. We also believe that, unless the proposed Refinery Investment Credit provisions are adjusted, there will be no meaningful contributions from that segment in meeting the LCFS targets.

As mentioned earlier, we have met several times with ARB during the re-adoption rule development period and after the ISOR was released, and continue to urge ARB to reset the 2020 target CI reduction level to a more realistic and sustainable level of approximately 4.5%, as indicated by our internal projections and those of BCG's most recent study that WSPA has been shared with staff.

## Low-CI Fuel Availability

### Supply and Blending Limits for Renewable Diesel

Chevron believes that renewable diesel is one of the more promising available low carbon intensity fuels for LCFS compliance. However, ARB's supply projections are optimistic and overly reliant on announced projects and nameplate capacities.

The critical barriers to the market penetration of renewable diesel, however, are not production levels but blending infrastructure and regulatory hurdles. ARB has projected that renewable diesel will make up 12% of the California diesel pool by 2020, but we anticipate it will reach roughly half that level. Logistical hurdles on pump labeling (FTC regulations), superimposed on the fungible nature of the common carrier pipeline system will be difficult to overcome in the 2016-2020 timeframe. We project that the vast majority of diesel in the state will contain 5% renewable diesel by 2020 with higher percentages seen in select centrally-fueled fleet applications, resulting in an overall pool average at 6% renewable diesel.

ARB staff has speculated that regulated parties may pursue several options for getting around the 5% blending limit imposed by FTC labeling rules.

- <u>Segregated grades of diesel at terminals</u> – Staff contends that selling two blend levels (0-5% and 6-20% renewable diesel) would enable higher blend levels.

  This option is problematic as terminals face multiple logistical constraints when it comes to any attempts at additional product segregation (e.g. plot space for additional tankage). Even where it could be considered, it is highly unlikely to occur until LCFS implementation establishes RD supply stability and justifies the investment in expansion of diesel grade infrastructure.

- <u>Moving entire pipeline/terminal systems to higher blend levels</u> – Some terminal position holders could move to 6-20% blends, causing the retailer community served by those terminals to label accordingly.

  Voluntarily industry adoption of an RD6-RD20 specification is equally problematic. The existing fungible pipeline system dictates that industry must move in "lockstep" for any geographic move to higher blends. Such a change would have to be implemented through common carrier pipeline specification change, which would be difficult to achieve short term for competitive reasons. While unlikely before 2020, this is the most likely path forward longer term. It will just take time for the dynamics of the market to make such a dramatic change.

- Large-scale fleet blending – Bypassing the traditional supply system to blend high renewable diesel levels for fleet applications.

  This is a very real possibility. Centrally-fueled fleet blending at higher renewable diesel percentages will likely occur but its impact is small and it has already been comprehended in our estimates.

- Relying on an FTC re-interpretation of the underlying law (2007 EISA) – The FTC may revisit their understanding of Congress' intent and remove the regulatory barriers.

  This is the least likely solution. Several unsuccessful inquiries have already taken place by both fuel providers and renewable diesel producers as expanded blending has been pursued for Renewable Fuel Standard and other blending mandate compliance. The FTC has been unmoved on this point. Congress providing the necessary authority (by reopening EISA) is even more unlikely near term; strong opposition is expected by the biodiesel lobby to any revision attempt.

Given all of this, terminal blending above 5% before 2020 is highly unlikely and fleet blending will have only a marginal impact on the overall market balance, bringing the statewide average to approximately 6% vs. ARB's forecast of 12%.

## Biogas Projections

Reliance on large-scale production of renewable natural gas as a supply of LCFS credits is questionable. Investors will weigh high regulatory risk as they consider such projects. Without RFS and LCFS credit subsidies, renewable natural gas for transportation is uneconomic. Cellulosic RINs are estimated to add three times the commodity value of natural gas and the LCFS may add another one to two times the value. While this may seem like a significant motivator for investment, the possibility that these programs may be modified at any time (based on political and/or regulatory reassessment) represents a significant issue for investors as they consider projects whose returns are based solely on the RFS and/or LCFS credit premiums that they generate.

Typical economics (capital investment, absence of need for gas "cleanup", access to gas pipeline, etc.) of biogas utilization drive the application of such gas to power generation and not motor fuel use. We have cautioned ARB that the GHG reduction benefits associated with "re-purposing" biogas from power generation to CNG/LNG production are not appropriately accounted for in staff's estimates. ARB's carbon intensity assessment of these products ignores this very real possibility, taking full credit for any renewable CNG/LNG production as though it represents green-field landfill gas production. Should it be found that a significant portion of the landfill gas supply used for CNG/LNG production was redirected from electricity production, much of the compliance value of those biogas products will have been lost.

The current version of CA-GREET2.0 estimates the lifecycle CI of CNG from landfill gas to be 17 gCO2e/MJ. If this landfill gas was re-purposed from on-site electricity generation, the amount of electricity displaced from the grid would need to be accounted for as average grid electricity, which has a much higher CI than electricity from landfill gas. CA-GREET2.0 estimates the US-average electricity CI to be 183 gCO2e/MJ, while EPA has estimated the CI of electricity from landfill gas to be 11.4 gCO2e/MJ. EPA also estimated that 3.4 MJ of landfill gas energy is required to produce 1 MJ of electricity[1]. The increase in the landfill gas CNG/LNG CI from displacing landfill gas (LFG) electricity would therefore be:

(1 MJ Elec. / 3.4 MJ LFG) * (183 - 11.4 gCO2e/MJ Elec.) = 50 gCO2e/MJ LFG

For the example above (Landfill Gas CNG), the CI would increase from 17 gCO2e/MJ to 67 gCO2e/MJ if re-purposed from on-site electricity generation, or about the same as fossil natural gas.

## Cellulosic Biofuels

ARB staff continues to strongly assert that the LCFS program (and more particularly LCFS credit prices) will drive advanced biofuels production. Evidence that the RFS2 program is struggling in meeting its advanced biofuel objectives does not appear to be materially impacting staff's estimates. Chevron notes that almost all of the advanced biofuel production facilities ARB and others mention are not in California – challenging the notion that the state is really driving the advanced biofuel market and attracting investments. As previously commented by WSPA in its Wood Mackenzie and BCG contractor work in 2012, the LCFS will draw any limited quantities of these fuels that may be available to California via shuffling resulting in sub-optimal costs and often increased emissions.

When calculating/projecting future biofuels supply, ARB should not rely on press announcements as credible evidence of actual facilities/volumes, since many projects are cancelled after initial press announcements but prior to construction, based on engineering studies that are completed and a more definitive cost estimate becoming available. ARB should count facilities that have started construction for potential facility/volume availability in the next 2 – 3 years. If construction has not started, then a discount factor of at least 50% should be used in projecting future capacity. When using past growth rates and projecting them into the future, ARB should take into account the period of two or so years of essentially no growth.

The ARB documentation is lacking in terms of detailed data to clearly support the contention that the program is still feasible. A full analysis of what supply of low-CI fuels is truly available to California and at what projected cost; what the supply logistics (marine, rail, etc.) are available to accommodate these alternative fuels; what infrastructure is needed to blend, transport and

[1] "Support for Classification of Biofuel Produced from Waste Derived Biogas as Cellulosic Biofuel and Summary of Lifecycle Analysis Assumptions and Calculations for Biofuel Produced from Waste Derived Biofuel," U.S. EPA Office of Transportation and Air Quality Memorandum to Docket EPA-HQ-OAR-2012-0401, July 1, 2014.
Table 6: CI of Electricity from Landfills that Flared Biogas = 12 kg CO2e/mmBTU (= 11.4 gCO2e/MJ)
Table 5: Efficiency of Electricity Generation from Biogas = 11,700 BTU biogas/kWh (= 3.4 MJ biogas/MJ electricity)

dispense these fuels; what incentives are needed for consumer acceptance; and other regulatory impediments should all be delineated.

## Cost Containment Mechanism

Staff maintains that sufficient low-CI fuels and credits will be available and, thus, the cost containment mechanism will be seldom (if ever) needed. Staff's stated expectation is that the cost containment mechanism will only be invoked when necessary to respond to some short-lived market "blip" or disturbance that will quickly give way to reestablishment of equilibrium. Staff acknowledges that this tool is not designed to accommodate systemic and prolonged LCFS credit shortages. They consider the ability to carry deficits forward (albeit with interest) for up to five years an "insurance policy" and they see no particular negative aspects to the end-of-year credit clearance market they are proposing (where regulated parties must buy their pro-rata share of pledged credits at a price as high as $200/MT).

We are opposed to the inclusion of such a cost containment mechanism in the LCFS because we believe that it will not accomplish its stated objective (contain prices) and will instead have a number of undesirable (and unintended) consequences. More specifically, the Credit Clearance Market (CCM):

<u>Does not stipulate a mechanism for retiring deficits, if multi-year market shortages persist</u>.
If there are inadequate credits available in the year-end auction of credits pledged by suppliers at prices as high as the pre-determined "cap" price, then regulated parties will have to carry a deficit into the following year. As presently designed, carrying over a deficit is an involuntary act by the regulated party – it is not caused by its own failure but by the failure of the market to meet the demand with sufficient supply. Consequently, imposing a 5% deficit interest subjects the regulated party to an unfair and inequitable penalty that only increases the deficit. Our analysis projects that the market will in fact be consistently short credits year after year, and if the annual obligation is not corrected to match actual credit supply, then the regulated community will be facing ever-increasing and interest bearing deficits.

<u>May drive credit costs up (if credits are withheld from the regular market for CCM price)</u>.
During periods of rising prices (i.e., credit shortages in the open market), the CCM will not keep credit prices in check. In fact, in a credit short year, the CCM is meaningless as there will not be any remaining credits to be brought to the table by sellers. The compounding of "interest" on the carryover/deferred balances will ensure credit buyers soak up the available pool of real LCFS credits in the market during the year and not wait for the CCM. The pool of real LCFS credits available is fixed – it is only their price that remains in question. Staff's setting of the price at $200/MT will serve as the benchmark for credit prices in that environment.

During periods of stable or declining prices (i.e., credit surplus in the open market), the CCM cap price creates an artificial "floor" value below which sellers will be hesitant to offer real LCFS credits for sale to the regulated community at substantially lower prices. This would artificially increase compliance costs – as credit prices will be artificially raised to (or near) the ARB cap and very few transactions will take place before the end-of-year sale. Credit trading would be seriously impaired as the open market would not be allowed to function as it should.

<u>Provides no liability protection against invalid credits secured through the CCM.</u>
Later we identify, in general terms, how the lack of a liability defense available to obligated parties from fraudulent credit sellers is inequitable. However, in the specific context of the CCM provisions, not only is there no liability defense for fraudulent or otherwise invalid credits, there is also no opportunity to conduct due diligence of the sellers. Moreover, ARB's time-table to organize and complete the CCM, suggests that the agency will not be doing any screening of the pledged credits.

<u>Offers no connection between CCM outcome, program off-ramps, future CI reduction targets</u>
The liquidity of the LCFS credit market is not only essential to the program's success. The absence of such liquidity is a clear signal that the program's CI reduction targets are overly aggressive and will render the program infeasible. There is presently no provision in the CCM to conduct a comprehensive program review in the event of repeated credit shortages.

<u>Does not adequately define mechanics of deficit carryover (recordkeeping, reporting, etc.)</u>
Even if all of the above issues were somehow resolved satisfactorily, the CCM proposal in the ISOR and draft regulatory language is sorely lacking in the execution/implementation details that would allow us to understand exactly how it would work. For example: What is the "order" of applying generated credits (through blending or purchases) to the various potential uses for a regulated party on any given year (e.g., meet the current year's obligation, retire previous years' obligations)?

Finally, the proposal to make public the long and short credit positions of regulated parties undermines the competitiveness of the credit market by disclosing confidential business information. The release of such information would allow competitors and sellers insight into a regulated party's confidential compliance strategy. Using this information and average market pricing, one could estimate the financial impact of LCFS compliance on a regulated party.

<u>Recommended Alternative to the CCM</u>
In lieu of the CCM, Chevron favors a dual approach of setting reasonable, practically achievable CI reduction targets and holding frequent (biennial) program reviews to ensure that the program remains on track and the LCFS credit market is healthy. More specifically, we would like to see staff eliminate the proposed CCM and:

- Provide for biennial mandatory program reviews with the first one completed by 1/1/2017. The initial review should include LCFS credit history including actual credit generation, obligation, and a comparison of actual current credit bank versus staff's projections in the ISOR. As part of the review, staff should include a projection of where the credit bank is expected to be two years later when the next review is due. If overall credit generation is above or below staff's projections (plus/minus a modest estimate allowance/tolerance), CI reduction targets should be adjusted up or down to re-establish an aggressive yet achievable program.

- Establish triggers that would require early program reviews prior to the planned dates outlined above. Specific, measurable thresholds and triggers should be established as part of this process. Some example of such triggers for an early review of subsequent year CI targets include:
    - Monthly credit price exceeds $150
    - Industry credit bank falls below 5 million metric tons (MMT)
    - CA fuel price >70cpg above national average

- Incorporate a simple carryover rule for one-off company imbalances. We would recommend tailoring the provisions of this segment along the lines established for RINs by EPA in the RFS program, with additional enhancements. Key features include:
    - A regulated party may carry over a deficit balance for one year, without penalty
    - Carryover credits must be retired in the following year to completely settle the deficit balance
    - A deficit balance cannot be carried over two years in a row
    - Retirement of any credit shortfall that an obligated party still has at the end of the carryover year, if it is determined that sufficient credits are not available in the market to satisfy the deficit balance (as well as deficits carried over by others). Once again, this situation would force an automatic program review.

This simple-to-execute approach would satisfy staff's stated goal of addressing short-term tightness in the credit market, while avoiding the market-manipulating aspects of the proposed CCM. Neither this solution nor the CCM can address the very real possibility of a long-term credit shortage. This must be met with the program reviews and schedule adjustments recommended above.

## Refinery Investment Credits

It is unlikely that the refinery credits of 1.13 MM $MTCO_2e$ in 2020 projected in ARB's compliance curve will be possible. According to the Initial Statement of Reasons, 80% of the 400 refinery efficiency projects identified in the referenced ARB Energy Audit study are now in place, resulting in 2.2 MMT $CO_2e$ reductions. Only 0.6 MMT $CO_2e$ identified projects remain, just half the amount in ARB's compliance curve. It is not clear that these remaining 20% will proceed given the fact that they have not been pursued already.

As described below, restrictions on qualifying projects will significantly limit available credits. The proposed 0.1 CI threshold implies that a relatively large emissions reduction of more than 1% of a refinery's emissions per project is required for a project to qualify. Because most, if not all, of the large energy efficiency projects have already been completed ("low-hanging fruit"), a majority of the remaining opportunities are relatively small. However, the cumulative potential of several small projects should not be ignored. Past investments in energy efficiency will limit potential for additional reductions, especially for more efficient refineries, thus remaining improvements are lower than ARB's projections.

The proposed thresholds and restrictions included in the proposed refinery investment credit mechanism risk arbitrarily eliminating most potential emission reduction projects. Changes are necessary to make the proposal viable and equitable. Chevron in particular has a long history of investing in energy efficiency projects and operating with industry-leading efficiency. Due to our prior investments, the proposed limitations and restrictions create arbitrary inequities. We suggest the following modifications to the refinery credits section to address these issues:

- Ensure equity for more efficient refineries by using methodologies that do not discriminate against complex refineries or penalize prior investments.
- Avoid arbitrary restrictions and thresholds, including 0.1 gCO2e/MJ CI and 10% biofeedstock limits, to encourage innovative GHG reductions.
- Eliminate the prohibition on criteria pollutants, as they are adequately regulated by multiple other programs.
- Clarify definitions and language in the rule, for specificity and to increase equity.
- Reduce projections for credit generation to a more realistic level.
- Review refinery carbon intensity gap between GREET and ARB calculations.

### Define an equitable industry benchmark

The proposal to handle differences in refinery efficiency (credit varies depending on whether a refinery is above or below the California average carbon intensity for each fuel) is a step in the right direction to ensuring equity. However, emissions per barrel of gasoline and diesel (carbon intensity) are not an appropriate method for comparison due to structural differences in refinery complexity and product mix. The 50% credit for higher-than-average carbon intensity refineries could adversely affect more efficient, but larger and more complex, refineries that produce a range of products.

We propose a Complexity Weighted Barrel (CWB) benchmark, consistent with AB32 cap and trade. Solomon's Complexity Weighted Barrel (CWB), has been implemented for the AB32 cap and trade emissions benchmark to ensure that more complex or diverse product slate refineries are not unfairly penalized. For consistency, we recommend ARB adopt the California average emissions per complexity weighted barrel (4.32 Tonnes Co2(e)/CWB) as the determining threshold for which less efficient refineries qualify for partial (50%) credits. This threshold is consistent with the refinery benchmark of 3.89 allowances/CWB, or 90% of California refinery average. For LCFS, if a refinery has more than 4.32 tons of greenhouse gas per CWB, it should only receive partial credit under the LCFS program, while refineries that have less than the average CWB intensity should receive full credit.

### Allow credit for projects implemented since LCFS adoption

The proposed January 1, 2015 permit date limitation for eligibility penalizes early actors contrary to AB 32 provisions 38560.5(b)(1) and (2). We propose that the deadline for project eligibility be the start of the LCFS in 2010, for fairness and consistency. The major investments identified by the Energy Audit have already implemented over 2.2 MMT CO2e/yr reductions and these projects should be eligible to apply for LCFS credits on a go-forward basis. Should ARB retain the proposed January 1, 2015 cutoff date, Chevron believes ARB should allow refinery greenhouse gas emissions reduction projects to be eligible if implemented (i.e., started up) after that date, regardless of when permits for the project were initially filed. Since permitting can be a multi-year process this will avoid penalizing refineries that are already proceeding with such projects. Moreover, since some projects may not necessitate permit applications this approach would apply a consistent threshold to all projects.

### Remove impractical restrictions and thresholds

Several revisions are recommended that may increase success of this new LCFS channel. As it is written the program will not incentivize reductions because it is fatally flawed by the following restrictions and thresholds that could be extremely difficult to achieve:

- Biofeedstock 10% threshold
- 0.1 gCO2e/MJ threshold
- Allow non-capital or offsite investments
- Criteria air pollutants and toxics should remain outside the scope of the LCFS

### Biofeedstock percentage of 10% is technically impractical for larger refineries

We recommend ARB reconsider and eliminate the 10% biofeedstock threshold. The threshold is inequitable; the quantity of biofeedstock supply necessary to meet this threshold for larger facilities becomes impractical. A 200,000 BPD refinery would require 20,000 BPD of bio-feedstock, nearly 10 times more than a typical 2000 BPD (i.e., 30 MGY) biodiesel plant. Furthermore, co-processing biofeedstocks is generally technically possible only below 10% due to unsolved process technology constraints. Eliminating this threshold could allow innovation to occur.

### CI reduction threshold of 0.1 gCO2e/MJ eliminates many legitimate projects

The threshold of 0.1 gCO2e/MJ is overly restrictive and inequitable; we recommend eliminating it. Especially for larger refineries, which may be 100 times larger than a typical biofuel plant, the absolute quantity of CO2 emissions required to cross this threshold is larger by a similar ratio. Also, with an industry average refinery carbon intensity (excluding tailpipe CO2) of only 7.61 gCO2e/MJ for gasoline and 8.95 gCO2e/MJ for diesel, 0.1 gCO2e/MJ is a relatively large reduction. This threshold is even more challenging for larger, more complex facilities, and for those that are already more efficient than industry average.

### If thresholds are included, use absolute rather than percentage emissions impact

Percentage throughput limits are unfair to larger refineries, since the absolute reductions must be larger as facility size increases. This is a perverse outcome, since the larger refineries may be more efficient at the start and therefore should not be precluded from further improvements. Similarly, if CI is calculated based on volume percent of each fuel produced, a refinery's fuel slate will affect its ability to receive LCFS credits for energy efficiency projects. If two refineries have total emissions of 4,000,000 tonnes each, but one produces 10% diesel, while the other produces only 5%, the number of tonnes of emissions reductions necessary to meet the diesel CI target will be different for each refinery (40,000 or 20,000). If thresholds must be included, we recommend an absolute emission reduction threshold (e.g. 1000 MT/year), rather than a per-unit measure.

### Consider including non-capital projects, bundled projects, and offsite portions of projects

Non-capital but sustained improvements should be included since many energy efficiency upgrades are considered non-capital. Also to simplify accounting and increase the success of this pathway, in the same application package ARB could allow bundling of smaller projects. Offsite portions of projects, such as hydrogen plants, could also be made eligible.

### Allow de minimis criteria pollutants and overall site offsets

The LCFS should focus on the reduction of GHGs and avoid the additional and unnecessary complexity of regulating emissions that are covered by strict stationary source regulations and CEQA. This is supported by ARB's analysis that concluded that emissions increases at the statewide, regional, or local level are unlikely based on current law and policies that control industrial sources.[2] Furthermore, this provision is inequitable as other credit-generating activities in the LCFS (e.g. alternative fuel pathways, electricity credits, etc.) do not include similar provisions.

At a minimum, Chevron recommends that ARB allow refiners to offset any criteria pollutant and/or toxics health risk impact associated with their submitted efficiency improvement projects. The LCFS should provide refiners the opportunity to offset any criteria pollutant increases related to GHG reduction projects and only require that when de minimis levels are exceeded, using similar thresholds as the Air Pollution Control Districts for criteria pollutants. Adding flexibility to meet such a de minimis criteria pollutant threshold with other offsetting reductions is more practical than the implications of attempting to track second-order criteria pollutant cascading impacts of GHG reduction projects throughout the refinery's operations.

### Clarify definitions and language in the rule

Chevron requests that ARB clearly define the following to enable effective implementation of the rule:

- Percent bio-feedstock calculation
- Total volume and energy calculations included in the allocation formula
- Quantification of baseline and reductions
- Harmonization with AB32

### Percent bio-feedstock calculation

If the percent biofeedstock restriction is not removed, ARB should clarify whether percent is relative to crude oil feed, intermediate feeds such as VGO or hydrogen, or gasoline and diesel individually, and how this is to be calculated. We also propose that ARB specifically define that these biofeedstock credits apply to both coprocessing bio-oils and coprocessing bio-gas biofeedstocks.

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[2] *CARB, October 28, 2010, Cap-and -Trade Regulation, Volume VI, Appendix P: Co-Pollutant Emissions Assessment*

### Total volume and energy calculations included in the allocation formula

The formula for calculating the total volume and energy of the refinery appears ambiguous. In particular, the basis of the product volumes is not defined. Use of life cycle assessments and other studies to calculate total volume and energy as proposed in this formula is not a technically sound method for allocating energy and emissions to products which fall outside the LCFS. For example, emission allocations between products based on volumes are not representative for refineries that make lubricants or other products besides gasoline and diesel. In order to avoid an arbitrary allocation while still incentivizing projects, a simplified formula could simply allocate the total emission reductions from any given project to that refinery's gasoline and diesel production.

### Quantification of baseline and reductions

For calculating baselines and reductions, please define type of measurement needed, for instance CEMS, Parametrics, EFs, etc. The LCFS is generally based on a 2010 baseline year but this program seems to be using a 2011-2013 average baseline, the expected baseline year should be clarified. Also the regulatory text is not clear as to how unrelated changes in refinery carbon intensity over time would affect previous refinery credits (such as changes in throughput rates or operational changes such as new units).

### Harmonization with AB32

For ease of implementation, the proposed definitions of the LCFS should be harmonized with the AB32 requirements such as MRR reporting.

### Explain apparent inconsistency on petroleum refining Carbon Intensity

According to staff's reported values, there exists a 5 to 7 gCO2e/MJ gap between GREET and ARB calculated industry carbon intensity values for gasoline and diesel. ARB's calculated refinery carbon intensity shown in Initial Statement of Reasons Table III-9 below is 5 gCO2e/MJ below the GREET model for California gasoline, and 7 gCO2e/MJ for diesel. This relatively large difference implies that on average, California refineries have lower actual carbon intensity than modeled by GREET's baseline. These data may indicate a gap in the accuracy of the GREET model, or in the proposed refinery carbon intensity formula. California refineries have been aggressive in implementation of energy efficiency improvements, and petroleum fuels should receive full and fair credit for improved carbon intensity in the LCFS program.

Staff investigated the actual carbon intensity of the gasoline and diesel produced by refineries using data from 2011 to 2013 and Equations 14 through 16, above.

**Table III-9. Gasoline and Diesel Refinery Carbon Intensities**

| | *CA-GREET ($gCO_2e/MJ$)* | *Industry Average ($gCO_2e/MJ$)* |
|---|---|---|
| Gasoline | 13.94 | 8.95 |
| Diesel | 15.33 | 7.61 |

Table III-9 lists the average carbon intensity for gasoline and diesel for all refineries. The average gasoline carbon intensity is 8.95 $gCO_2e/MJ$. Figure III-8 shows the average CI for gasoline for all refineries.

# Electricity Provisions

## Electricity Credits for Fixed Guideway Transit and Electric Forklifts

Chevron opposes the allowance of LCFS credits for fixed guideway transit and electric forklifts for the following reasons:

- Allowing these credits does nothing to encourage the development of new, low-carbon transportation fuels. Instead, the rule change simply allows the generation of funds from credits sold back to transportation fuel providers and does nothing to further reduce GHG emissions. The value of these credits is estimated by ARB staff to amount to $40 to $100 million for fixed guideway systems and $10 to $25 million for forklifts in the 2015-2020 timeframe.

- Much of the equipment that could generate credits has been in existence for many years – in some cases for decades. As such, only the incremental increase in electricity usage relative to the 2010 baseline should be allowed for credit generation. Staff partly acknowledges this inconsistency by not allowing the use of an Energy Economy Ratio (EER) when calculating the amount of fuel energy displaced for forklifts and only allowing its use for fixed guideway system expansion beyond 2010.

- Chevron believes that any credits generated for electric forklifts should be based on metered usage and not calculated based on estimates and assumptions. Staff proposes that electrical distribution utilities (EDUs) would be the regulated party for forklifts and that electricity usage would be estimated based on national shipment data, battery size, assumed annual operating hours, and load factor. Statewide data would be allocated to each service area on the basis of each utility's share of business/commercial accounts. Chevron is strongly opposed to this approach as there is no way to verify that the estimated electricity usage is real. Notwithstanding our opposition on the basis that much of the equipment receiving credits has been in service for many years, if ARB were to go forward with this credit generation scheme, it should be based on metered data that can be directly tied to the vehicles in which the electricity is used.

- Staff has assumed that electric forklift charging will displace diesel fuel in calculating credits. Considering many forklifts are powered by LPG, this is a questionable assumption. ARB has not provided data or information to validate this approach. Therefore, it is not possible to verify that the credits will be accurately generated.

### Elimination of Metering Requirement for Residential EV Recharging

The current regulation allows the use of an estimation procedure to approximate residential electric vehicle (EV) recharging electricity usage. However, that provision was to sunset at the end of 2014, and instead electricity used for EV recharging was to be based on direct metering. ARB staff is now proposing to eliminate the requirement for direct metering of electric vehicle (EV) recharging at residences in the post-2014 timeframe. Chevron strongly opposes this proposal for the following reasons:

- All parties participating in the LCFS, both opt-in and required, must be held to the same set of standards with respect to reporting, recordkeeping, validation, etc. Allowing a simple estimation procedure for some fuels and rigorous reporting and recordkeeping for others establishes an uneven playing field among fuel providers.

- Basing credits on an estimation procedure increases the risk of invalid credits. At the very least, credits generated via an estimation procedure are more likely to be open to challenges and invalidation.

Notwithstanding Chevron's opposition to this proposal as noted above, if ARB does go forward with an estimation procedure for determining the amount of electricity used for EV recharging, it needs to be much more rigorous than the current method approved by ARB (see http://www.arb.ca.gov/fuels/lcfs/workgroups/elect/04122013-caletc-letter.pdf). Based on the limited information available in this approval letter, it appears that the method would assume that vehicles within a service area without direct metering would be used in the same fashion as those that do have direct metering. We have a number of concerns and questions about this approach:

- Vehicle owners who go to the trouble of installing a separate meter are likely to plug-in more faithfully than those who do not and are therefore not representative of the entire fleet. This is particularly important for PHEV estimates. To justify the estimation methodology, data must be presented to confirm that the results from the metered fleet can be extrapolated to the unmetered fleet.

- The data collected on vehicles with direct metering cannot be applied to the entire fleet of BEVs and PHEVs in an area without also confirming that the distribution of vehicles (by BEV/PHEV and by all-electric range) is the same between those with meters and those without. It is highly unlikely that this distribution would be the same. For example, a PHEV with a 10-mile electric range that was purchased primarily for carpool lane access would likely be under-represented in the sub-set of vehicles with at-home meters.

- A method for avoiding double-counting of electricity usage must be included. If at-home charging for those vehicles without a separate EV meter is accounted for with this method, the method must account for a vehicle owner who only charges at public or work-based charging stations and rarely charges at home. Estimating home usage but then giving full credit to public charging stations has significant potential for double counting.

- At the May 30, 2014, workshop, ARB had proposed to exclude some supplemental information now required in annual reporting. It is unclear from the ISOR whether this change will be implemented. However, if so, Chevron disagrees with this, particularly the exclusion of the number of EVs operating in a service territory. Without this basic piece of information, it will not be possible to cross-check reported electricity usage by EVs for reasonableness. In fact, we suggest that the reporting requirements be enhanced to include not only the number of EVs in a service territory, but also the number of plug-in vehicles in various categories (i.e., pure electric vs. plug-in hybrids by range).

- It is important to distinguish between pure battery electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEV), and within each of those categories, identify the distribution of vehicles by electric range. For example, data collected by the Idaho National Laboratory on in-use driving patterns for the Chevrolet Volt and Nissan Leaf can be found at: http://avt.inl.gov/evproject.shtml#. Dividing the all-electric miles by the number of vehicles reported at that website gives quarterly VMT per vehicle for Oct-Dec 2013. The BEV Leaf (~6000 miles per year if 4Q2013 numbers are forecast to a full year) is accumulating fewer miles on electricity than the PHEV Volt (~8000 miles per year). Clearly, the limited range of the Leaf is resulting in much lower VMT than a typical new car, while the broader utility of the Volt results in greater overall usage and higher VMT on electricity. However, PHEVs with lower range would have fewer miles on electricity, while BEVs with greater range would likely have more miles on electricity. These results reinforce the importance of understanding the make-up of the plug-in fleet in a particular area to generate an accurate estimate of on-road electricity usage. In addition, it is important to continue monitoring recharging and electricity usage of these vehicles as the patterns of usage may change as the vehicles expand beyond "first-adopters."

**Elimination of Public Reporting of Electricity Credit Information**

Chevron does not support removal of this requirement from the regulation. The current regulation requires regulated parties for residential and public EV charging to include a public accounting of the number of credits generated, sold, and banked in annual compliance reports. In the ISOR, ARB argues that because public credit accounting is not required of regulated parties of other fuels it is not necessary for electricity. Chevron supports the principle that all fuels and fuel providers should be subject to the same requirements – ARB should not pick "winners and losers." Our positions outlined above with respect to electricity credits for fixed guideway transit/electric forklifts and elimination of metering requirement for residential EV recharging are consistent with that principle. However, if electricity credits are based on estimated electricity usage rather than direct metering, the public has a right to know precisely how those estimates were prepared and the number of credits generated as a result.

## Updates to the OPGEE Model

### General Treatment of Crude Oil in the LCFS

Chevron continues to disagree with the crude differentiation approach that ARB has adopted for the LCFS. As several studies have shown, such an approach leads to inefficiencies in the crude market and could potentially lead to "shuffling," with an increase in GHG emissions associated with increased transportation distances. Ultimately, if crudes are valued based on their carbon intensity (CI), there is no evidence to suggest that they will not be produced. In addition, if crudes are valued based on their CI, many crudes produced in California will be at a competitive disadvantage relative to other crudes imported into the state. We encourage ARB to re-think the efficacy of the differentiated crude approach.

### "Ground-Truthing" OPGEE

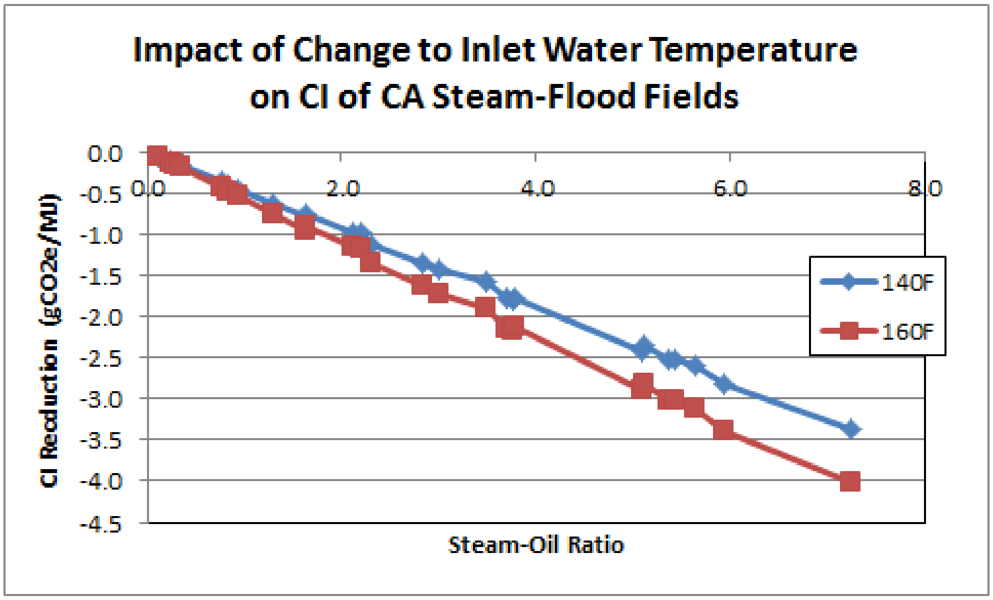
ARB staff, in conjunction with researchers at Stanford University, has continued to make revisions to the OPGEE model over the past several years. The OPGEE model relies on numerous inputs and assumptions about oil field attributes and operational parameters such as field depth, reservoir pressure, number of production wells, number of injection wells, water-oil ratio, gas-oil ratio, steam-oil ratio, API gravity, etc. For many oil fields, little data are available for the input parameters and the model populates the entries with "smart defaults." The CI estimates from OPGEE must be validated against actual data for a given field in California, the U.S., or elsewhere. Given the importance of the crude CI estimates in terms of establishing the 2010 Baseline crude CI and the California-average crude CI for each calendar year, this "ground-truthing" is an important test of the validity of the model approach that should be undertaken.

### OPGEE Inputs

As noted above, many inputs are required to run the OPGEE model for a particular oil field. For California fields, a number of important parameters, such as water-oil ratio, steam-oil ratio, and production volumes are available or can be calculated from data published by the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources. One such input parameter, the steam-oil ratio (SOR), has a significant influence on the CI calculated by OPGEE for an individual field. The amount of energy required (and therefore the GHG emissions associated) with a given SOR is calculated using a heat balance over the steam generator. A critical input to that calculation is the temperature of the input water to the steam generator. The OPGEE model assumes a default water input temperature of 40°F and provides no rationale for this assumption.

Based on Chevron's experience with steam-flood fields in the San Joaquin Valley, a value of 40°F for inlet water temperature to steam generators is much too low. Because water that is input to steam generators is typically recycled from water produced in the field, its temperature is well above 40°F. For our fields in the San Joaquin Valley, the inlet water temperature typically ranges from 140°F to 160°F, and in some cases is even higher.

The figure below shows the impact on the CI of California steam-flood fields if the inlet water temperature to the steam generators was 140°F and 160°F instead of the assumed default of 40°F. As expected, the influence is greater on fields with the higher SOR values. For SORs in the 5 to 6 range, the CI of the crude would drop by 2.5 to 3.5 gCO2e/MJ by using more realistic estimates of the inlet water temperature. This reflects a CI reduction of 8% to 11% for those fields.



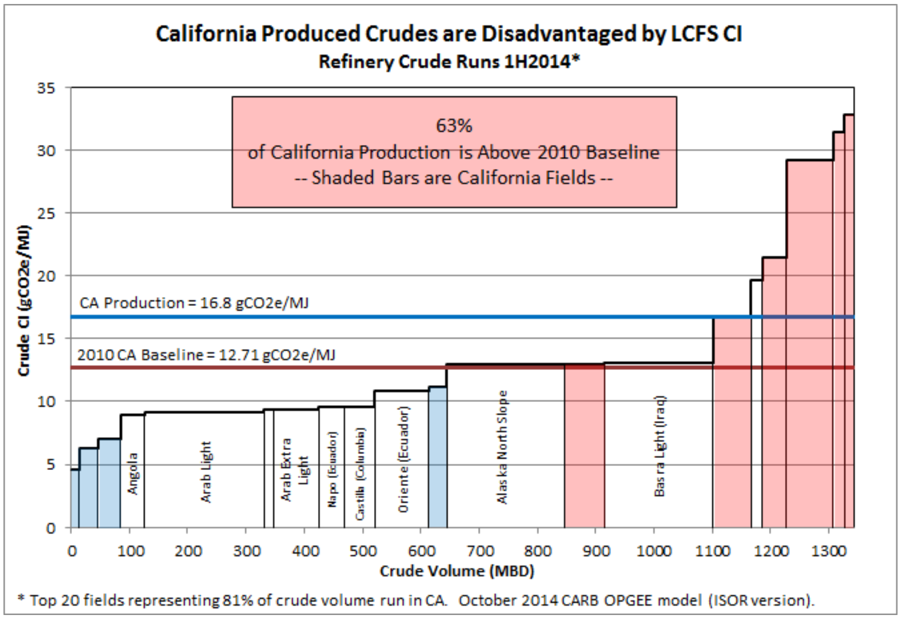

We encourage ARB staff to revise the OPGEE modeling to reflect a realistic input value for the steam generator feed water temperature, and we will work with ARB staff to provide more specific data on this and other model inputs. As these values will be static for several years once finalized in the regulation, it is important to get them right.

## California Crudes are Disadvantaged Under the LCFS

In the 2009 regulation, crudes produced in California were not subject to the high carbon intensity crude oil (HCICO) requirements of the standard as they constituted more than two percent of the 2006 baseline crude mix run in California refineries. The trigger level of two percent was put in place to ensure that ***new crudes*** introduced into the California market with high CI values would have their increased GHG emissions mitigated. This was not intended to punish California producers as their GHG emissions are already regulated under the broader AB32 program.

The current construct of the regulation puts California crudes at a distinct disadvantage. As observed in the figure below, California production averaged 16.8 gCO2e/MJ based on field volumes for the first half of 2014 (see http://www.arb.ca.gov/fuels/lcfs/crude-oil/mid-2014-crude-ave-ci.pdf) and the CI values in Table 8 of the proposed regulation. In addition, 63% of California production has a carbon intensity greater than the 2010 baseline value of 12.71 gCO2e/MJ.

We encourage ARB staff to develop a more equitable treatment of California crudes in the LCFS that recognizes that GHG emissions from the production of those crudes are controlled via AB32. ARB should develop a single CI value for all California crudes without differentiating among the ~150 fields included in the current crude CI lookup table. Changes to that CI value should only be made in the event of a significant change to the average CI of California fields, e.g., +/- 1 to 2 gCO2e/MJ.




## Operator-Specific CI Values

ARB currently evaluates the CI of California oil fields as a single value, although there may be multiple operators within each field with much different operating parameters. If crudes are ultimately valued based on their CI, there should be the ability for individual operators to obtain a separate CI specific to their operation. This would award operators for more efficient operations, similar to what has occurred in the biofuels industry (e.g., there are scores of different CI values for corn ethanol).

## De Minimis Level Incremental Crude Deficits

As currently written, incremental deficits are incurred if the California-average crude CI for a particular year is greater than the 2010 Baseline crude CI. In order to avoid increased regulatory and reporting burden for small changes in crude CI, the difference between the California-average crude CI and the Baseline crude CI should exceed a de minimis level (e.g., 0.1 gCO2e/MJ) before an incremental deficit is incurred.

## Regulatory Language

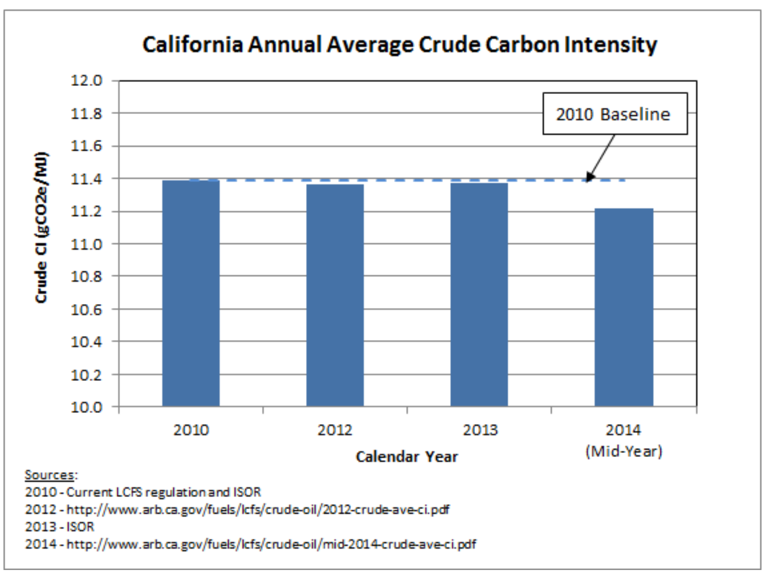
Pages 95-96 of the Proposed Regulation Order contains the regulatory language for calculating the incremental deficit if the California-average crude CI for a given year exceeds the 2010 Baseline crude CI. We have the following comments on the proposed regulatory language:

- The language needs to be clear that the parameter $E^{XD}$ (fuel energy, in MJ, for either CARBOB or diesel) is for the calendar year for which the deficit is calculated.
- The language needs to be clear that the parameter $E^{XD}$ is for fuel **supplied** to the California market; the current language refers to fuel "produced in California or imported into California." Fuels produced for export should not be subject to this regulatory requirement.
- The current language appears to calculate debits based on the amount of fuel supplied in the year in which the debits become effective, which is two years after the debits are incurred. Instead, this should be based on the amount of fuel supplied during the year that the debits are incurred.

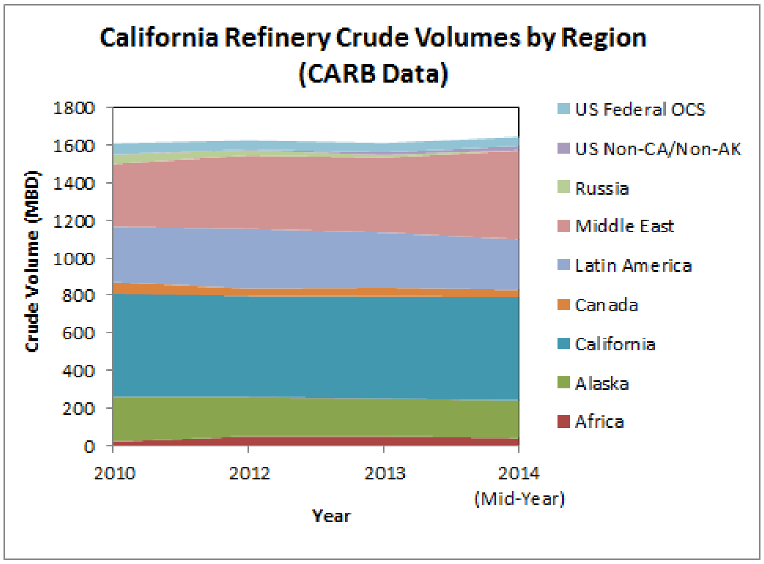
## Annual Crude CI Calculation

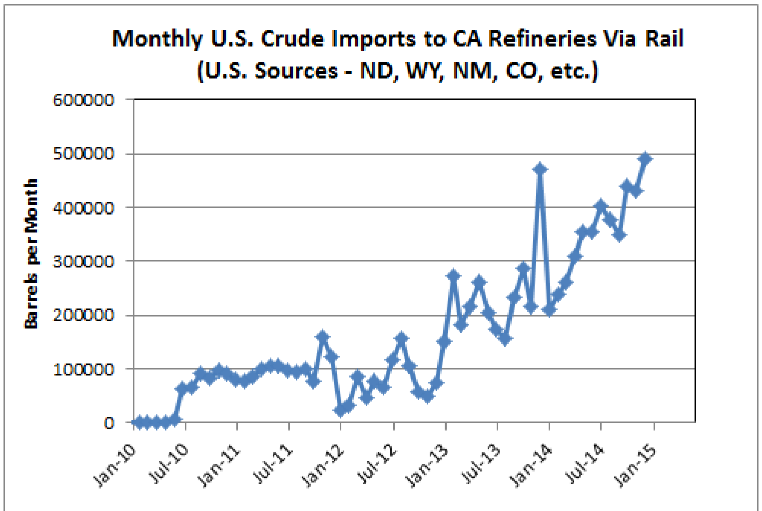
Chevron appreciates ARB's desire to continually improve the accuracy of LCFS data inputs, and recognizes the approach taken by staff in attempting to refine the crude handling provisions as part of the re-adoption rulemaking is consistent with that principle. However, we also believe that the degree of crude differentiation built into LCFS, to comprehend concerns over CA crude CI increasing over time, remains unnecessarily excessive and should be reduced. Our reasoning is as follows:

- The fundamental reason for these provisions in the rule was to ensure that the Average carbon intensity of the California crude slate did not increase over time. The available crude breakdown data for recent years (2012-1H2014) suggests that this threat has never materialized and that the CA crude average CI has remained relatively stable.




- Moreover, ARB data on crude volumes run in California refineries show a decreasing trend in heavier Canadian crudes, while light Middle Eastern and U.S. mid-continent crudes ("US Non-CA/Non-AK" in the figure below) have trended upwards. Furthermore, CEC data on U.S. mid-continent crude imports by rail show strong growth over the past three years that has continued through the second half of 2014.




Source: California Energy Commission
http://energyalmanac.ca.gov/petroleum/statistics/2010_crude_by_rail.html
http://energyalmanac.ca.gov/petroleum/statistics/2011_crude_by_rail.html, etc.

- As a result, we believe that the justification drivers for installing, maintaining and expanding the current LCFS crude differentiation provisions have been greatly diminished since these provisions were implemented.

- Even if ongoing monitoring is necessary to ensure that staff's concerns that a heavier crude CI outlook does not materialize, the worst case scenario (i.e., exporting heavy California crude to maintain a constant annual average crude CI) yields no tangible greenhouse gas reduction benefits from a global standpoint. California's average crude CI may well remain constant, but global GHG emissions are likely to increase as the GHG emissions associated with transporting the crude exported from California (to non-optimal refining centers for processing) will be higher.

- The ongoing staff effort to maintain and improve crude differentiation inputs and modeling tools in LCFS is resource-intensive for the Agency and equally burdensome for our industry in terms of the recordkeeping and reporting requirements it entails. In the absence of a valid GHG justification for engaging in such a complex crude differentiation and tracking scheme, we believe staff should be moving in the opposite direction than they have been following, i.e., one of simplification and streamlining.

We understand that staff does not propose a fundamental change in the California Crude Average approach as part of this re-adoption package. We support staff's decision not to proceed with refinery-specific crude accounting for large, complex refineries and understand the rationale offered for doing so. We agree that there is no practical alternative to facilitate detailed individual crude breakdown in the pipeline crude blends that comprise a large part of refinery crude inputs in the state. We look forward to working with staff in the near future to examine potential options to modify the crude differentiation requirements in LCFS (post re-adoption), toward a less complex alternative that can hopefully satisfy staff's desire to track crude CI trends over time while reducing the compliance burden on our industry.

We note the proposed changes in the methodology for calculating the CA crude average to rely on CA on-shore crude production data (supplied by The Department of Conservation- DOC) and off-shore data (supplied by The Bureau of Safety and Environmental Enforcement- BSEE). This is in lieu of refinery-reported crude volumes that have been used for this purpose heretofore. Staff's rationale is simply that this is essential to improve the accuracy of the crude volumes used in the calculation of the CA Annual Crude Average. There is no backup support or analysis of the impact of the proposed changed in calculation methodology. More specifically, staff does not:

- Present data to determine how this change will impact the calculated annual volume averages to date. Staff merely indicates that total refinery-reported volumes for 2012 and 2013 closely match the volumes reported by CA field operators. We would recommend a more rigorous side-by-side comparison for 2011-2013 using the CA crude volumes estimated/reported by refineries versus the newly proposed utilization of DOC and BSEE data.

- Elaborate on the methodology that will be used to combine the in-state crude data with out-of-state crude volumes imported into California (both U.S. and foreign) to develop the overall annual CA crude average. Furthermore there is no indication that any potential discrepancies with the refinery-reported volumes will be investigated and reconciled.

- Recognize the difficulty that increased CA exports will entail should this methodology be adopted, dismissing such concerns by simply indicating that production volumes will be adjusted for exported crude volumes (should the need arise). Staff believes their proposal will work as long as all CA-produced crude is processed in CA, which is currently the case. However, staff's proposal appears to be short-sighted and inconsistent with the overall crude handling approach in LCFS which, despite WSPA's input, is designed to drive increased crude exports to prevent CA crude average CI increases. Moreover, the same issues staff outlines in breaking down reported volumes of typical CA pipeline crude blends currently will be in play if/when staff tries to back out exported crude volumes out of the calculated CA annual average.

## Indirect Land Use Change

### General Comments

Indirect land use change (ILUC) estimates continue to be a source of uncertainty in the overall lifecycle GHG footprint of biofuels, and significant efforts to refine those estimates have continued since ARB initially included ILUC in the LCFS. Although uncertainty in the estimates remains, Chevron agrees that ILUC effects need to be addressed in the context of the LCFS regulation. In principle, the scientific basis for addressing ILUC in the LCFS remains sound, and improvements to methods and models for estimating ILUC values continue to be made.

During the 2009 rulemaking, the Board directed staff to convene a Work Group with experts on both sides of the debate to ensure a balanced and transparent approach to further work on the issue. We applaud ARB for facilitating that effort, as well as the work group participants who devoted considerable time and energy to better define the issues around indirect effects. Although disagreements remained among experts about some key elements of the ILUC calculations (e.g., time accounting), there were other areas of agreement and recommended GTAP model improvements that have been incorporated by Purdue University and ARB (e.g., improved treatment of co-products for corn ethanol and soy biodiesel).

### Specific Comments on the ILUC Analysis Presented in Appendix I of the ISOR

The detailed analysis of revised ILUC values is summarized in Appendix I of the ISOR. While we believe the inclusion of ILUC is relevant and necessary to a valid assessment of lifecycle impacts, the process for establishing and updating ILUC values should be open and transparent. To that end, we have the following comments and questions on the analysis and the ensuing results. We request that ARB address these questions as they proceed to finalize the modeling updates and rulemaking.

A comparison of the current regulatory ILUC values and the proposed ILUC values is shown in the table below. Also shown are values presented at the November 20, 2014, workshop.

| Comparison of Current and Proposed ILUC Values (gCO2e/MJ) | | | |
|---|---|---|---|
| Fuel Pathway | Current Value (2009 Regulation) | Proposed Value (December 2014 ISOR) | November 2014 Workshop[3] |
| Corn Ethanol | 30 | 19.8 | 20.0 |
| Sugarcane Ethanol | 46 | 11.8 | 19.6 |
| Soy Biodiesel | 62 | 29.1 | 27.0 |
| Canola Biodiesel | n/a | 14.5 | 14.5 |
| Sorghum Ethanol | n/a | 19.4 | 12.7 |
| Palm Biodiesel | n/a | 71.4 | 46.4 |

Given the significant changes to both the GTAP model, which estimates the location and amount of land use change for a particular biofuel pathway and a given volume "shock," as well as the emission factors applied to the land use change (via the AEZ-EF model), it would be useful for ARB staff to identify how much of the ILUC changes in the table above are associated with GTAP model revisions versus emission factor revisions. Additionally, what is the basis for the changes between the November 2014 workshop and the December 2014 release of the ISOR?

Table I-1 of Appendix I summarizes the "shocks" used in GTAP to model ILUC emissions. For sugarcane ethanol, the table appears to indicate that 3 billion gallons of Brazilian production and 1 billion gallons of U.S. production were assumed. Is this a correct interpretation of the table, or do those volumes reflect the volumes consumed in Brazil and the U.S.? If the former interpretation is correct, what is the basis for these estimates, as we are not aware of large volumes of sugarcane ethanol being produced in the U.S.? What is the sensitivity of the model to changes in the split between Brazilian production and U.S. production?

The proposed ILUC values are based on an average of 30 model runs which used 5 different values for the yield-price elasticity, 2 sets of values for a yield adjustment for the cropland pasture land category, and 3 sets of values for the elasticity of crop yields with respect to area expansion (5 X 2 X 3 = 30 runs). ARB also prepared a Monte Carlo uncertainty analysis that consisted of up to 1,000 model runs for some pathways. Why were the means of the 30 discrete scenarios used to establish the ILUC values rather than the means of the Monte Carlo simulations?

As noted above, one of the parameters that was varied to establish the 30 model runs for the ILUC analysis was a yield adjustment for the cropland pasture land category, which is a new land category in the GTAP model relative to the 2009 analysis. This yield adjustment is intended to account for potential investments to increase the productivity of this land as it is brought into crop production. The discussion on page I-12 of Appendix I indicates:

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[3] See http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/112014presentation.pdf

> *However, Purdue researchers acknowledge that although they believe the effect is real, there is no empirical basis for the elasticity parameter proposed for this endogenous yield adjustment.*

In the absence of empirical evidence to estimate this parameter, staff used two sets of values for the runs employed for each biofuel analyzed here. Given the lack of empirical data with which to estimate this parameter, Chevron requests that staff clarify the basis it used for the elasticities in this analysis.

Land use change effects for cellulosic ethanol are discussed beginning on page I-18 of Appendix I. The discussion indicates that a value of 18 gCO2e/MJ is proposed for cellulosic feedstocks, and that staff is continuing to work on model inputs for cellulosic ethanol from non-food crops and waste. The discussion further indicates that results will be published when the analysis is complete. Will an updated ILUC value be proposed for cellulosic ethanol via a 15-day change notice as part of the current rulemaking, or does staff envision another avenue to formalize this value? In what timeframe does staff expect to have an updated ILUC value for cellulosic feedstocks? Is the 18 gCO2e/MJ value only for farmed trees, miscanthus, and other purpose-grown cellulosic feedstocks, i.e., would waste products used for cellulosic ethanol feedstock be assigned a land use change value of zero?

## Low Complexity/Low Energy Use Refinery Provisions

Chevron is opposed to ARB's proposal to allow low complexity / low energy use refineries to generate credits equivalent to 5 gCO2e/MJ for their CARBOB and CARB diesel production. The criteria proposed for identifying these refineries is questionable as it ignores energy used per barrel of production in favor of total energy used by the facility. This unfairly penalizes those refiners who have invested in the complex facilities required to meet the demand of the California market at the state's unique specifications. We also oppose this proposal as it adds additional complexity to an already extremely complex program.

### Refinery-specific crude provisions

The proposal to allow low complexity / low energy use refineries to opt out of the California crude average is also inappropriate. As we and others have stated repeatedly, crude differentiation under the LCFS does not benefit the environment, consumers, or regulated parties and may increase GHG emissions as crude shuffling increasing transportation impacts. Any move to make that differentiation more complicated only serves to compound the problem. There is little benefit to this change to the program or regulated parties and, as ARB states in the ISOR, tracking field-level crude use is extremely complicated. While it may be somewhat easier at the small refinery level, the added complexity of tracking multiple class-level crude CI baselines and usage is not worth the questionable benefit to those choosing to opt out.

### Innovative crude production

ARB's proposed revisions to the LCFS innovative crude provision, Section 95489(d) are creative and perceptive and address several issues identified as inhibiting the use of innovative crude production methods to reduce GHG emissions. As staff noted in the Initial Statement of Reasons (ISOR) no application has been submitted to date under the current provision. The supported changes include 1) allowing the crude producer to opt in and earn LCFS credit based on the volume of crude supplied to California refineries, 2) reducing the minimum threshold for CI reduction from 1.0 g/MJ to 0.1 g/MJ and allowing projects not meeting the 0.1 g/MJ threshold to be certified if they reduce annual emissions by 5,000 MTCO2e or more, 3) adding solar and wind electrical power generation and solar heat generation to the allowable innovative methods, and 4) the use of simplified, default credit calculations for solar-based steam generation and solar-or wind-based power generation.

However, in keeping with the intent of the innovative crude provision as stated in the ISOR, to promote the development and implementation of innovative crude production methods, additional adjustments to the provision and Staff proposed revisions should also be considered. First, the source and sink of the CO2 used for Carbon Capture and Sequestration (CCS) should not be restricted. LCFS credits should be provided regardless of where capture and storage occurs, not if both are solely onsite at the crude production facilities. This added restriction is contrary to the 2014 First Update to the Climate Change Scoping Plan which promotes innovative strategies such as CCS use to reduce GHG emissions from electricity generation and industrial emitters. Such geographic limitation would further dis-incentivize CCS in California as the overall economics for a third party's carbon capture project would be diminished as most amenable, readily capture volume, carbon capture opportunities are not onsite at the oil production facilities. While the capture of CO2 from a steam generator at the oil production facility may be an admirable objective, the overall cost of actual capture, sufficient volume, gathering and clean-up to a CO2 purity to allow for miscible injection and recovery at a reasonable economic scale is prohibitive as compared to capture from power generation or other industrial emission streams.

Also, this same limitation requiring onsite generation for solar heat generation and solar or wind electricity generation should be removed. There are no less GHG emission reductions if the oil field operator generates or purchases his power onsite. Greater benefit would be achieved by focusing on regulating emission sources and not emissions footprint. Chevron's solar to steam test project in the Coalinga Field would not qualify for innovative crude consideration under the current definition, although having met the revised emissions reduction threshold, as the mirror field was on adjacent property to the oil operations.

Reducing minimum acceptable steam quality from 65% to 55% for solar steam generation would also be appropriate as several existing oil fields generate steam at a steam quality lower than 65%. This change and increasing the assumed inlet water temperature from 40 F to 140 F and reducing the steam generator pressure from 2000 psi to 700 -1000psi in the crude credit quantity calculation would be more accurate in representing typical oil field operations. Hot produced water is primarily used for steam generation.

While ARB is commended for expanding the list of allowable innovative methods, any new oil recovery method that reduces GHG emissions beyond the required threshold should be allowed to submit their project for Executive Officer consideration as approved innovative technology crude. As an example, the use of polymer flooding in the Wabasca Field in Canada instead of steamflooding for enhanced oil recovery would not qualify for consideration under the current proposed revisions.

## Reporting and Recordkeeping

### Quarterly Reporting & Reconciliation

Chevron supports and appreciates ARB's proposal to change the quarterly reporting process from a simple 60-day reporting deadline to include a 45-day deadline for reporting, followed by a 45-day reconciliation period. Given the extremely large volume of transactional data involved in compiling these quarterly reports, this structured approach to business partner reconciliation should help to alleviate reporting discrepancies.

Even then, discrepancies are never completely avoidable as billing errors, volume adjustments, and other corrections can occur well after the reporting deadlines. Chevron appreciates that ARB has retained a provision in the regulations for regulated parties to request the reopening of prior quarterly reports for corrections. We support the use of the LRT-CBTS as the vehicle for submitting these requests, as indicated in the proposed regulations. We do not, however, see the need for the accompanying letter on letterhead described in the ISOR. This is an unnecessary manual step that adds no discernable value to the process.

### Product Transfer Documents

The revised definition of Product Transfer Document (PTD) is problematic. The new definition describes the PTD as a single document that contains "information collective supplied by other fuel transaction documents, including bills of lading, invoices, contracts, meter tickets, rail inventory sheets, Renewable Fuels [sic] Standard (RFS2) product transfer documents, etc." This is in direct contrast with the traditional definition of "product transfer document" under this and other regulatory programs, including the Renewable Fuel Standard and other EPA and state programs. The term is specifically generalized so that required information and messaging can be included on any of the types of documents indicated, without requiring the expense and process burden of generating a new document for every new regulatory program. This definition should be corrected to refer to a document or "collection of documents" that transmits the required information for the LCFS program.

### Reporting Exports

In the ISOR, ARB proposes to require that a party who sells fuel without obligation report any subsequent export of that fuel by the buyer or any subsequent buyer. This is impractical as there is no way for one party to monitor the movement of fuel owned by another party, particularly in California's fungible supply system and especially if the fuel changes hands again after the initial sale. While ARB proposes to require PTD language stating that any subsequent export of fuel sold without obligation must be reported, this PTD language does not create a legal obligation for the buyer to notify the seller of the export. More importantly, it is inappropriate and unreasonable for ARB to assign the compliance burden related to an export of fuel to anyone other than the actual exporter. The fact that another party at one time held title to that fuel is not sufficient justification for assigning the CI obligation for that fuel to that party for an export decision made by another. It is understandable that ARB wants to track the export of fuels in order to keep the LCFS program whole, but they must assign any associated compliance burden to the actual exporter. This concept has been successfully incorporated into the Renewable Fuel Standard, where an export of renewable fuels results in a renewable volume obligation for the exporter, and there is no reason why the same approach cannot work here.

## Enforcement

### Violations/Civil Penalties

The LCFS, similar to the federal RFS, imposes liability for the validity of the submitted credit on the submitter. Essentially, this is a "buyer beware" program, where the buyer is expected to conduct due diligence of the credit to establish that it was not fraudulently created and the CI valuation is accurate. The LCFS, as presently drafted, would require the party that submits a credit that was subsequently invalidated to replace those credits, and be potentially subject to civil penalties. As we have seen with the RFS, however, such a system did not prevent extensive fraud which undermined market confidence in small producers. We propose that the LCFS adopt an affirmative defense from civil penalty and credit replacement upon a showing that the invalidity of the credit was caused by a third party and the regulated party neither knew nor should have known of the cause of the invalidity at the time it was submitted for compliance.

Though responsible parties are obligated to exercise diligence and make good faith efforts (and include attestations of accuracy), the volumes of data and the complexity of the reports creates a potential for errors that cannot be eliminated. Since an error may go undetected for months or years, assessing a per day violation for incomplete or inaccurate reports from the date of submittal as proposed in § 95494(b) will produce penalties that are grossly disproportionate to the harm. Therefore, if the error is discovered by the regulated party, it should be afforded an opportunity to cure within 5 business days of discovery without penalty. If the error is discovered by ARB, then penalty should accrue upon the date of notice that the report is incomplete or inaccurate. For un-submitted, incomplete or inaccurate reports, the per-day maximum penalty amount should not exceed $1000 per day.

In instances where a civil penalty is to be assessed for an invalid credit, we support ARB's proposal that penalties be assessed on a per credit basis (a maximum of $1000/MT), rather than on a per-day basis. Time- based penalties are often magnified by variables unrelated to the alleged violating act such as by the time required to investigate a suspected violation and obtain the necessary facts to make a determination. Consequently, time based penalties are often disproportionate to the violating conduct.

### Authority to Suspend, Revoke, or Modify

ARB should establish an administrative hearing process to allow regulated parties an opportunity to appeal a ARB decision to suspend, revoke or modify a credit or CI valuation.

## Severability

ARB proposes added a section to the regulations stating that any declaration of one part of the program as invalid would not invalidate the remainder of the program. A general assertion of severability is inappropriate and ignores the interdependence of the LCFS provisions. There are many provisions in the LCFS that significantly impact other provisions, and if declared invalid would render the regulation unworkable. For instance, if the CI values for out-of-state producers were nullified, compliance with LCFS would become impossible in the near term, if not immediately.

## Economic Impact Analysis

The economic impact analysis presented in the ISOR is based on a number of projections and assertions that we find troubling.

### Cost of Credits

ARB applies an upper limit of $100/MT in its economic analysis. This limit naturally has an effect on ARB's assessment of the cost of the program to regulated parties, other business, individuals, and state and local economies. Given ARB's proposal for a Credit Clearance Market with a $200/MT price cap, we believe that $200/MT should be the upper limit used in the economic analysis. Should the market fall short of meeting ARB's credit supply projections, there is a very real possibility that the $200/MT price cap will become a price floor for a significant portion of the available credits.

### Production Volumes and Price of Low-CI Fuels

We disagree with the assertion that "Since 2010, the production of low-CI fuels has increased in response to the financial incentives provided by the existing LCFS regulation." (p. VII-4) While there has been some incremental reduction in the average CI of corn ethanol supplied to California, sugarcane ethanol imports were at lower levels last year and there still today is no cellulosic biofuel available in large quantities. Also, while biomass-based diesel production levels are up, this could be attributed to the federal blender's tax credit and the federal Renewable Fuel Standard (RFS) rather than the LCFS.

### Revision of Program Goals

We are surprised with the new *stated* goals of the program (p VII-11) – "To create a durable regulatory framework that can be adopted by other jurisdictions". This is not one of the goals described in Governor Schwarzenegger's executive order establishing the program.

### Flawed Macroeconomic Analysis

The macroeconomic analysis is flawed based on some faulty assumptions. As stated, the scenario should be run at a maximum credit price of $200, adjusted for inflation, from 2016 through 2020.

The macroeconomic analysis assumes that production of conventional fuels in CA remains static due to increasing exports ( VII-14). Thus, GHG emissions are not lowered but exported.

Additionally, no impact of lost margin has been taken into account for increased exports, nor have capital effects of exporting been addressed.

### Additional Sensitivity Cases Are Needed

ARB needs to include an analysis on the impact to the program if the low-CI products are not available as projected. Also, existing fuel trends which show a decreasing demand in California do not account for low crude oil prices. A scenario should be modeled reflecting a $50/barrel crude oil environment.

Table VII-7 of the ISOR shows ARB's projections related to fuel consumption in 2016 and 2020 under a baseline scenario (no LCFS) and an illustrative compliance scenario (with LCFS). While the table indicates expected growth in renewable diesel and biodiesel, it indicates no growth whatsoever caused by the LCFS in the use of ethanol, electricity or natural gas for transportation. This contrasts directly with ARB's assertion in part VII-E of the ISOR that the LCFS is a necessary complement to the federal RFS because "the potential value of electricity, hydrogen, and natural gas are not considered in an overall program to reduce the carbon intensity of transportation fuels." Yet ARB projects no effect on the consumption of these fuels because of the LCFS. Given the complexity and projected cost of the program and the significant uncertainty regarding ARB's projections regarding the availability of these fuels, it is highly questionable whether the LCFS is worth re-adopting.