Nick Economides
Manager

Chevron Products Company
6001 Bollinger Canyon Road
San Ramon, CA 94583
Tel 925-842-5054
Nick.Economides@chevron.com

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[Submitted Electronically]

Mr. Samuel Wade, Chief
Transportation Fuels Branch
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: California LCFS Revisions–Comments on ARB Pre-Rulemaking Package from August 7, 2017 Workshop

Dear Mr. Wade:

Chevron appreciates the opportunity to review and comment on the referenced LCFS workshop. Chevron is a major refiner and marketer of petroleum products in California. The proposed revisions directly and indirectly affect Chevron's compliance requirements under the Low Carbon Fuel Standard (LCFS), which in turn impacts our transportation fuel business and customers. Chevron is a member of the Western States Petroleum Association (WSPA). We support and incorporate by reference the joint comments submitted by WSPA in response to this workshop.

Chevron is pleased the California Air Resources Board (ARB) is preparing to implement improvements in several provisions of LCFS regulation. We believe it is appropriate for ARB to evaluate every possible avenue for attaining the state's environmental objectives and we are looking forward to continuing our work with staff to ensure the regulation amendments are practical, cost-effective and do not impose unreasonable compliance burdens on regulated parties. Our detailed comments can be found below, following the numbering sequence of the slides presented by staff on August 7:

1. Overall state of completeness; regulatory timetable; models to develop compliance curve through 2030 (Slides 1-6 and 9-15)

In general, the state of completeness of this rulemaking package is substantially below what we would have expected given the rulemaking timeline presented in Slide 9. We hope staff will make progress in refining the concepts and approaches put forth on August 7 in many key areas and have a much more complete package for review by the next workshop anticipated in late September/early October. It is challenging to provide substantive comments on the topics outlined given the degree of vagueness in staff's presentation and the small incremental presentation of information above and beyond what has already been shared by staff (and commented on by stakeholders) throughout the series of workshops on individual topics that began in 2016.

We note the absence of specific sections (or slides) dedicated to key topics for our industry such as CCS and coprocessing. We understand that work continues on CCS and that staff's initial proposal may be available by the end of August. We will defer commenting on CCS until that package is issued. However, we continue to urge staff to adopt pragmatic and realistic guidelines for industry and to recognize that, beyond capital investment cost hurdles, regulatory burdens associated with long-term sequestration performance and liability concerns could easily derail any real commercial impetus for implementation.

We were surprised there was no section addressing coprocessing in the August 7 package. Staff has already held two workshops on the topic and the degree of interest among the various stakeholders appears to be high. We understand that a third coprocessing workshop has been scheduled for October 16 and we look forward to a more detailed view of where staff is heading on this topic. We urge staff to include coprocessing procedures and guidelines in the LCFS Amendment package and are concerned with comments offered by staff at the workshop that this may be deferred until staff receives some "real project" pathway applications. The feasibility and attractiveness of coprocessing projects will be largely impacted by the regulatory framework applied by ARB and, thus, we believe getting those implemented is a necessary pre-requisite to getting "real project" pathway applications.

Furthermore, many of the provisions detailed in the August 7 package affect coprocessing and need to be clarified, particularly if staff envisions substantial differences for coprocessing applications:

- Renewable propane treatment can significantly impact project economics (see comment on Slides 26-29).
- Renewable jet fuel credits should include renewable jet produced through coprocessing – there should be no difference to a fuel blender between imported renewable jet and internally produced renewable jet. We believe staff agrees with this view.
- Onerous bio-feedstock tracking provisions (discussed elsewhere) will have a similarly adverse impact on coprocessing. We urge staff to search for alternatives (e.g., bio-feedstock aggregator certification) to prevent the need for coprocessors to track their bio-feedstock all the way back up the distribution chain.

2. Livestock Pathways and SB1383 (Slide 7)

The single slide on Livestock Pathways and SB1383 offers little definition of the specifics staff is considering or the potential LCFS impact/contribution staff envisions out of dairy biomethane. It should not be assumed that LCFS stakeholders are necessarily involved to the same extent in the Dairy Working

Group meetings and, thus, a more detailed and thorough summary of the topics in the next LCFS workshop would be beneficial.

When implementing SB1383's required financial incentives for dairy projects, ARB should maintain a level playing field where each dairy project has equal access to any incentive and innovation in technologies and pathways is encouraged. If a put option or similar approach is used, it should be on a $/MMBTU or combined RINs plus LCFS basis, since LCFS alone is likely insufficient to mitigate dairy projects' risks, but would distort prices across the whole market to the detriment of consumers.

3. Environmental Analyses (Slides 11-12)

It is unclear what the CEQA Environmental Checklist is that staff is proposing beyond the general "identify and evaluate indirect impacts" purpose stated on the slide. We do not have a draft checklist to review at this point, but we are sensitive to potential impacts the environmental analysis may have not only on renewable fuel production but also on bio-feedstock production and distribution.

4. New Modeling Tools for Low CI Fuels Forecasts (Slides 16-17)

Slide 16, along with Appendix A describes ARB's proposed multi-stage approach to develop tools for scenario analysis and evaluation of potential compliance curves to set compliance targets to replace Tables 1 & 2 of the current regulation. While staff continues to seek input on the previously released Biofuel Supply Module (BFSM) model, it is still testing the California Biofuel Allocation Model (CA-BAM) that appears on this flowchart. However, staff will not release the latter model for stakeholder review and feedback until later this summer. We are concerned that this timetable may not allow sufficient time for stakeholders to evaluate the model and that the scenarios and conclusions it was used to develop internally may not receive adequate review.

ARB appropriately envisioned a "stakeholder engagement/public comment" step alongside each phase of the process shown on Slide 16. Seeking input from various stakeholders as well as SMEs, academia, *etc*. creates the appropriate level of peer review necessary to improve the accuracy and quality of the model and confidence in the final targets it was used to generate.

Additional Comments:

The process and the flowchart lacks timelines for each phase of the work. The reader may have difficulty getting the "big picture" and understanding when all this is supposed to come together. It would be useful if staff added timelines to the flowchart.

- In the flowchart, the "Public Comment" box needs to be connected to: "CA-BAM" and "Preliminary Evaluation" boxes by arrows, as explained in The Concept Paper Appendix A text.

- Concept Paper Page A-5, first sentence under Phase 4 heading: “phases 1-4” needed to be revised to “phases 1-3”
- “Compliance Calculator” box of the flowchart in Phase 4 of the process: the title for this box seems incorrect, as Compliance Calculator is developed in Phase 3 of the process. We suggest replacing it with a more descriptive tile like: “Scenario Analysis.”
- Similar to the bullet point above, the “Results” box description could be changed to a more descriptive title like “Target Setting.”

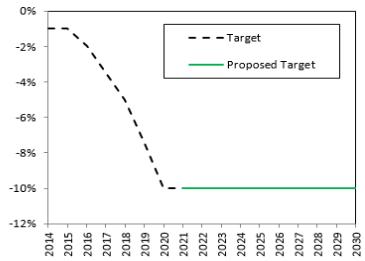
5. Preliminary evaluation of compliance calculator; conclusions regarding feasibility of 18% target for 2030 and closer look at the 2020-2023-time frame (once credit bank is exhausted); review of ARB fuel cost range estimates (Slides 18-21)

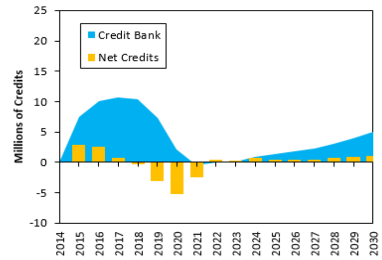
The Draft Illustrative Compliance Scenario Calculator could be useful to understand how LCFS targets are calculated, but we note that the tool, as released for the August 7th workshop, appears incomplete. For example, the three fuel supply scenarios modelled appear identical. For the assumptions that were included, the basis is unclear and questionable--some appear too conservative and others impractically optimistic. Also, it is unclear how or if overlapping regulations are explicitly included and ARB should clarify the impacts with and without these regulations (e.g., ZEV mandate, NOx SIP, SB375 community VMT plans, cap-and-trade). Regardless, the Illustrative Compliance Scenarios worksheet reinforces the problematic gap in the practical feasibility and uncertainties in meeting aggressive LCFS targets both before 2020, and in the 2020-2030 timeframe.

Our analysis of the most recent BFSM using a price estimate of $100/MT or even $200/MT shows a gap in 2019-2023 during which the model cannot meet a 10% or higher CI target with current pathways (specifically, the model only reaches 7% in 2020). Despite best efforts in modeling and forecasting, we draw attention to actual program results, in which ARB’s data for 1st quarter 2017 shows the LCFS credit bank is already drawing down—indicating the program may be unable to meet the current 3.5% reduction target.

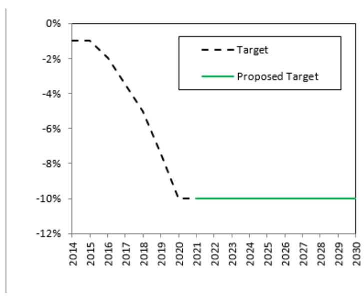
Using the Illustrative Compliance Scenario tool “as released,” below are some of its predictions, which illustrate the point that LCFS targets substantially above the current levels, are uncertain and potentially infeasible:

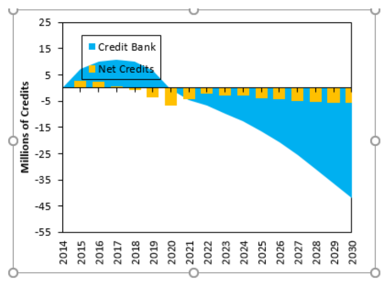
- If CI mandate held flat at 10% post-2020, the model predicts a slightly **<u>negative credit bank</u>** in the early 2020s even assuming a statewide 30% decrease in gasoline demand.



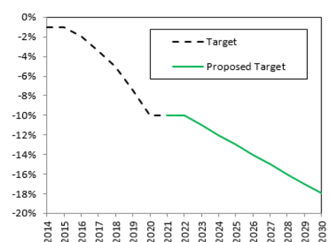


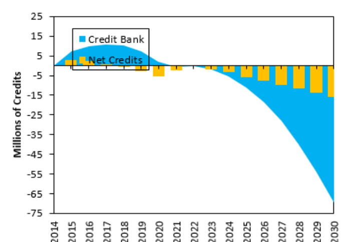
- If gasoline demand is assumed flat, with the 10% CI target held flat through 2030, the cumulative credit bank in 2030 is **negative 40 million MT**





- If CI is linearly decreased to 18% by 2030, even with a 30% decline in gasoline demand, the cumulative credit bank in 2030 is **negative 70 million MT**





We encourage staff to test the feasibility of targets using several other alternative scenarios with ranges of demand, technology, and cost assumptions that explicitly apply probability weighting factors and contingency factors in the modeling predictions (e.g., multiply each fuel type volume by a probability factor based on installed capacity and technology, and potentially subtract an additional contingency from the overall total estimate). These factors will mitigate any tendency to over-estimate the pace of LCFS credit generation (e.g., reference ARB's original and 2015 Readoption ISORs). This approach will significantly improve on the current approach of setting policy targets that appear to be infeasible, thereby undermining investor and market confidence and discouraging continual improvements.

As an alternative, staff could set feasible CI targets and gradually raise them as low-carbon fuels and pathways become available. An example of such a target progression would be increases in CI reduction target of 0.5%/year above prior year CI.

We urge caution relying on unproven models such as the BFSM and CA-BAM, no matter how sophisticated (meaning they rely on layers upon layers of assumptions and optimization algorithms that are difficult to validate and not transparent). Using commercially unproven government or academic assumptions and forecasts and outdated inputs can also result in unrealistic predictions.

6. Soliciting Continued Feedback (Slide 22)

We are pleased that staff is soliciting input on reasonable credit generation for petroleum provisions (innovative crude, refinery investment and renewable hydrogen) and address each of the areas mentioned individually in the corresponding slide comments. However, we are concerned that staff's proposal may not relieve some of the Refinery Credit generation constraints that currently limit its utility and potentially preclude several types of projects that should be eligible for credit generation. We urge staff to avoid limits on specific types of projects and make the calculation methods clear. We suggest using similar 3rd party engineering validation as used by CPUC utility industrial rebate programs. Consistent with our 2015 input, for the refinery investment credits we recommend the following:

- The eligibility criterion should be the startup date of when GHG reductions begin.
- The minimum CI impact threshold should be lowered to 5,000 metric tons, the same as for innovative crude.
- All investments that reduce lifecycle GHG emissions (and are verified) be allowed to generate credits regardless of the technology.

7. Allowing jet fuel to earn credits (Slides 23-25)

We support staff's proposal to allow alternative jet fuel to earn LCFS credits for the reasons presented in Slide 25 and under the terms outlined by staff in Slide 24, i.e., that conventional jet fuel would not generate deficits. We urge staff to clarify the eligibility of various parties in the distribution chain to earn such credits and clarify that fuel blenders introducing/blending renewable/alternative jet fuel into their product offerings would be the initial parties eligible to generate credits for doing so.

8. Reclassification (removal of exemption) for propane (Slides 26-29)

Allowing renewable propane credits in the market provides additional volume/flexibility for compliance in LCFS. However, since current sources of renewable propane are mostly by-products of biofuel production, there are several unanswered questions about what this will mean for the CI of the biofuels.

Would pathway holders need to recertify their fuel pathways if their processing scheme includes production of renewable propane for which no credit was available previously? Would they have the option to capture this credit or would it be mandatory that they recertify their existing pathways?

9. Reclassification (removal of opt-in status) for hydrogen (Slide 31)

We are indifferent on removing the opt-in status for hydrogen. We recognize that the benefits incorporating hydrogen has for consistent CI methodology may offset the added regulatory burden.

10. Third Party Verification (Slides 32-48)

Slide 34
We continue to support the need for comprehensive, required verification audits under the LCFS. We also support previous statements by established verification auditors that the LCFS regulations should set clear guidelines for these audits to avoid a “lowest common denominator” approach. We urge ARB to work closely with experienced, reputable QAP auditors to establish clear audit parameters and identify synergies between the needs of QAP audits and LCFS verification audits. This will result in reliable LCFS verifications and potentially mitigate the cost of audits covering both programs.

Slide 44
The proposed MCON verification deadline is very aggressive. ARB should consider the likelihood of material errors that may affect crude CI calculations in deciding when to set this deadline. Reported data should be presumed correct and the verification as an after-the-fact confirmation. A rushed verification schedule has a greater chance of affecting the accuracy of reported data than catching significant potential misstatements. The verification deadline should come at least two months after the reporting deadline to allow regulated parties to focus on preparing accurate reports.

Slide 45
We share the concerns of renewable fuel producers around tracing feedstocks to their ultimate source. Practical guidelines are necessary to avoid excessive cost to feedstock producers, feedstock aggregators, and renewable fuel producers. At the same time, validating feedstock supply chains is critical to ensuring the validity of the ultimate LCFS credits generated. In its concept paper, staff suggested that “some feedstock suppliers may elect to obtain separate verification services to reduce the potential for multiple verifications when they supply multiple fuel production facilities.” Chevron strongly supports this concept and suggests that ARB establish a feedstock supplier registry wherein feedstock producers or aggregators can register and undergo annual verifications to demonstrate the types and quantities of feedstocks supplied to producers. Renewable fuel producers could then have the option of either documenting their own feedstock supply chain or simply demonstrating that they bought from registered feedstock suppliers.

Slide 47
The regulatory language covering conflict of interest rules should be clear, specific, and direct. A conflict should only arise if an auditor performs services that directly affect a client's LCFS pathway information or LRT-CBTS reporting. Services related to other topics or other programs should have no effect. Any ambiguity in this area can lead to delays in the verification process and possibly potential providers simply opting out of the program entirely.

11. LCA Modeling Tools and Pathway Certification

<u>CAGreet revisions (Slides 49-51)</u>
GREET is well known for using scientifically-solid data that is well documented and, to an extent, transparent. We are unable to provide a complete assessment of the new model because the necessary documentation for CA-GREET 3.0 is currently unavailable. We understand that staff changes to GREET1 2016 will feature significant modifications to the ANL version, including:

- Electricity resource mixes from EPA eGRID 2014
- Emission factors for natural gas leakage, transmission, and fugitives
- EMFAC2014 tailpipe emission factors
- Chemical use data for ethanol, biodiesel and renewable diesel to reflect data from applications processed in 2016-17
- Efficiency values for liquefaction, compression, etc. to reflect data from applications processed in 2016-17
- Crude recovery and transport factors from an updated version of OPGEE
- Others as required

As with the previous revision to the CA-GREET model, staff expects that, after Board approval, all existing certified fuel pathways will likely need their CI values recertified in 2019 using the updated model (CA-GREET 3.0). We urge staff to detail the specifics of this transition in upcoming workshops before the issuance of the proposed rulemaking language.

The GREET model has previously treated air emissions from nonroad equipment used in farming and mining at a high aggregated level. To improve the ability of GREET to estimate criteria air pollutant emissions from nonroad equipment, air pollutant emissions outputs from U.S. Environmental Protection Agency's (EPA's) Motor Vehicle Emission Simulator (MOVES) model for nonroad equipment have been run to generate emissions for this equipment and were incorporated into the 2016 release of GREET. MOVES groups nonroad engines into 10 categories, and it estimates emission inventories for nonroad sources for criteria air pollutants, greenhouse gases, and air toxics in a given area over a specific period. We support the expanded emission factors that will allow GREET users to better characterize nonroad equipment air pollutant emissions, including agriculture and mining, as well as metals production. MOVES' granularity in comprehending nonroad machinery for agricultural operations is limited but sufficient to cover the majority of nonroad equipment used in biomass handling, which also covers the majority of ARB-approved pathways. Equipment that is specific to crops or plantations that require special machinery are expected to be submitted as separate cases by biomass producers. It is unclear to what extent ARB may replace (at least some) of MOVES values with EMFAC numbers and we would request staff clarification on this item in upcoming workshops.

With the rapid development of shale gas production in the past few years, significant efforts have been made to examine the methane (CH_4) emissions from various stages of natural gas pathways to estimate their life-cycle GHG emissions. Methane leakage rates have been a concern, but measurements and data collection were not available until recently. The GREET 2016 numbers (and by default, the CA-GREET values) for NG align relatively well with industry-accepted averages. CH_4 emissions from shale gas extraction are only slightly higher than those from conventional NG operations.

The GREET 2016 model includes updates of farming energy and fertilizer intensity associated with the farming of corn, soybean, willow, miscanthus, and switchgrass. Corn and soybean farming energy intensities are derived from a recent USDA report based on a USDA Agricultural Resource Management Survey (ARMS3) in 2010 and 2012, respectively (USDA report by Gallagher 20164). Similarly, corn and soybean farming fertilizer intensities are developed from a survey in 2015 available from the USDA National Agricultural Statistics Service (NASS) database (USDA 20165). And finally, the farming energy and fertilizer intensity of willow, poplar, miscanthus, and switchgrass are developed by using data from a recent Billion Ton Study analysis (BTS 2016). ARMS is a credible and reliable source for data and information from actual farming operations. Similarly, NASS is a survey of actual operations and a reliable source. Finally, the BTS has improved greatly since its first version was published in 2005. Since then, many of its shortcomings have been addressed and the numbers are more scientifically sound.

Electricity and petroleum products (e.g., gasoline, diesel, jet, residual oil, and liquefied petroleum gas) from crude oil are two of the baseline energy products that are commonly used in the various fuel production pathways in GREET. The energy and emissions intensities of electricity and petroleum products strongly depend on the electricity generation mixes and the crude oil mixes to the U.S. refineries, respectively, which change over time and vary by region. Therefore, the mix of energy sources and technologies used for electricity generation and petroleum production is updated annually in GREET. In the GREET 2016 model, the electricity generation mixes of the United States, eight NERC regions, and two additional states (Alaska and Hawaii) are updated by using the EIA's AEO 2016. Also, the crude oil mix supplied to U.S. refineries and the weighted average distance from each crude source are updated by using EIA's company-level imports data, AEO, and Canadian Association of Petroleum Producers' market report. This update should make the model more accurate – we do not foresee any issues.

Our preliminary impression of the new model's user interface is that it is more user friendly and streamlined. Below is a side-by-side comparison of a few cases run with the same assumptions in both versions of the model:

Feedstock	CA-GREET 2.0	CA-GREET 3.0
Corn ethanol-dry mill	76.15	75.36
Sugarcane ethanol	51.55	system glitch
Soybean BD	53.39	58.6297
Landfill gas - CNG	48.68	23.19
Grain Sorghum Ethanol	80.39	73.45

The new version of the model seems to have a glitch when trying to run the sugarcane ethanol pathway. The big difference in the landfill gas-to-CNG pathway is in the additional credits received for avoiding emissions in the production phase.

OPGEE Revisions & CA Crude Baseline (Slides 52-55)
We support the addition of duct firing for steam generation in OPGEE 2.0 as this should help more accurately capture the CI profile and cogeneration efficiency of such operations. We recommend further review of OPGEE's approach to subsurface reservoir pressure modeling and impact on electricity consumption for injection and artificial lift and are prepared to work with Dr. Brandt and ARB staff to ensure the new OPGEE model version accurately reflects commercial operations in those areas.

The existing LCFS regulation requires staff to assess the following items on a 3-year cycle and propose amendment to the LCFS regulation, if needed:

- Revisions to the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model
- Addition of crudes to the Carbon Intensity Lookup Table for Crude Oil Production and Transport (Table 8), and
- Updates to all carbon intensity (CI) values in Table 8

During a workshop on April 4, 2017, ARB released OPGEE v.2.0.a and made it available for public comments. Further to the received comments and just before another workshop on August 7, ARB released OPGEE v.2.0.b. ARB didn't release input files for OPGEE v.2 and released the "2010 Baseline MCON Input Spreadsheet" as part of the OPGEE v.2.b release. The absence of this input file has delayed the assessment of the new OPGEE version, even though we appreciate Dr. Brandt's eagerness to receive industry input and willingness to work with stakeholders to improve the model.

In general, all the changes made in OPGEE are positive and in the right direction. The number of inputs required to run the program have increased, however, and the model runs considerably slower. From

LCA point of view, the software boundary has increased making an already complex model even more complex.

A major concern with OPGEE has been with input data (number of inputs, accuracy, uncertainty, outdated (and in cases) scarce publicly available data). This remains a concern with the current version of OPGEE as well. Companies are working individually with Dr. Brandt and ARB staff to address these issues and are providing the necessary operational data input to ensure the crude CI values generated through the model accurately reflect current conditions and practices in the field.

We appreciate the help we have received from ARB staff in our successful effort to replicate the 2010 CA baseline crude average CI of 12.31 (gCO_2/MJ) with OPGEE v.2.0.b as reported by ARB on page 55 of “Pre-Rulemaking Public Meeting to Discuss 2018 LCFS Amendments” presentation. However, s staff has not released the “MCON Input Spreadsheet for Crude Lookup Table” for OPGEE v.2.b., we can’t currently verify any update to Table 8 of the Regulation. We hope this will be possible by the next workshop in early October.
Pathway Application Streamlining (Slides 56-61)
We support staff’s proposed pathway streamlining and are particularly pleased to see that most lookup table applicants will be able to register directly in the LRT and begin reporting fuel qualities without submitting data in the AFP. We agree with staff’s view that renewable hydrogen and renewable electricity lookup pathway applicants would first need to register in AFP to submit the necessary supporting data/documentation.

12. Lookup Table Pathway for EV Charging (Slide 62)

We are inclined to support the EV charging industry’s proposed improvements to the electricity provisions of the LCFS. Specifically, to enable:

- Offsite low-CI generation, solar as well as biogas
- Netmetering that does not double count RPS, with the same logic as the utility’s green tariff programs
- Flexibility for additional participants and credit calculation methodologies versus current ARB estimates for utility residential charging, that can quantify electricity usage and potentially directly balance low CI electricity sources with EV charging (e.g., as OEM vehicle telemetry, networked smart chargers, and community choice aggregators).

If electricity provisions are applied consistently to other pathways, we can support the proposal to use CEC data, but would suggest annual updates or 3 year average updates rather than quarterly.

We continue to urge staff to provide greater transparency into each step of their calculation and basis for input assumptions for credit calculations for residential EVs and forklift EVs and fixed transit credits, otherwise, it is difficult for market buyers to assess risk of invalidation. For example, there was a recent mistake and (upward) revision in ARB's EV credit calculations that was impossible for obligated credit purchasers to foresee due to lack of transparency.

13. Innovative Crude Provisions (Slides 64-65)

We have no issues with the proposed additional bins for steam quality in the Solar-to-Steam credit framework.

It is unclear to us what additional reporting may be required by staff as part of a solar-to-steam innovative crude credit application package and request staff provide clarification in this area. Staff should also clarify (or at least provide examples of) what other energy efficiency efforts can be considered as potentially available to generate credits through the innovative crude segment of the regulation

We continue to urge staff to consider solar and wind electricity production flexibility at crude production sites, allowing the size of the facilities to be optimized by permitting tie-ins to be made "above the local utility's electricity meter" at the subject facilities. This should enable the input of excess electricity produced during peak hours back into the grid to offset electricity drawn by the facility from the grid when no solar generation takes place.

14. RNG to Refinery Hydrogen Production & Refinery Investment Credit (Slides 66-67)

We agree with staff's new approach for calculation of benefits associated with Refinery Renewable Hydrogen production. Focusing on the CI difference between renewable and fossil-based feedstock to the refinery hydrogen plants is a significant simplification compared to the alternative of carrying the renewable hydrogen component through the complicated series of refinery process units all the way to the finished products.

We are prepared to work with staff in developing simplified, practical calculation methodology guidelines for projects that improve refinery energy efficiency. We recommend that staff's review focus narrowly on the particular segment of the refinery that the proposed project will impact and ensure that a project-by-project assessment takes place on the methods that will be used to ensure that the project benefits are verifiable and can be reported by the independent auditors as part of their annual audit.

15. Credit Transaction Guidelines (Slides 70-71)

In June 2016, staff proposed to advance credit transaction reporting deadlines to be 3 calendar days from the date of agreement for both seller and buyer. Despite ARB's clarification that a deadline falling on a weekend or holiday would advance it to the next work day, we are concerned that this timing is too tight. While most transactions are recorded this quickly, even a small number of unavoidable "late" transactions can put regulated parties at risk of breach of contract and enforcement action. Delays can be caused by communication issues, clerical errors, paperwork disputes, or technical difficulties. Chevron again strongly encourages ARB to establish a deadline of 5 business days to allow for these occasional issues. We understand that staff hopes to improve the timeliness of credit reporting data and expect that most activity will still be reported within the week of the transfer agreement.

Contact for Follow-up

Thank you for providing this opportunity for Chevron to comment on the August 7 Pre-Rulemaking LCFS Workshop package. If you have any questions regarding our comments, please contact Nick Economides (Nick.Economides@chevron.com; 925-842-5054) or Don Gilstrap (DGilstrap@chevron.com; 925-842-8903)

Kind Regards,

Nick Economides
Manager
Fuels Compliance