Responses to Comments

on the

Draft Environmental Analysis

for the

Amendments to the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations

CALIFORNIA AIR RESOURCES BOARD

Released September 17, 2018

to be considered at the

September 27, 2018 Board Hearing

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PREFACE

The California Air Resources Board (CARB or Board) prepared a Draft Environmental Analysis (Draft EA) for the Proposed Amendments to the Low Carbon Fuel Standard (LCFS) and Alternative Diesel Fuel (ADF) Regulations (Proposed Amendments). CARB included this Draft EA as Appendix D to the Initial Statement of Reasons (ISOR). Pursuant to court direction in the modified writ of mandate issued by the Fresno County Superior Court (Superior Court) in *POET, LLC v. California Air Resources Board* on October 18, 2017 related to CARB's prior CEQA analysis for the LCFS, CARB also prepared a Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation included as Appendix G to the ISOR.

On March 9, 2018, CARB released the ISOR and appendices (including Appendix D and Appendix G) for a 45-day public review and comment period that concluded April 23, 2018. Revisions to the Proposed Amendments were released for two 15-day comment periods starting on June 20, 2018, and August 13, 2018 and closing on July 5, 2018, and August 30, 2018, respectively. Including comments received during the April 27, 2018 Board hearing, a total of 292 comment letters were received on the Proposed Amendments during the public comment periods, 20 of which addressed the Draft EA and/or Appendix G.

CARB staff made minor modifications to the Draft EA based on responses to comments and other updates. To facilitate identifying modifications to the document, modified text is presented in the Final EA with ~~strike-through~~ for deletions and <u>underline</u> for additions. None of the modifications alter any of the conclusions reached in the Draft EA, introduce new significant effects on the environment, or provide new information of substantial importance relative to the Draft EA. As a result, these minor revisions do not require recirculation of the draft document pursuant to the California Environmental Quality Act (CEQA) Guidelines, California Code of Regulations, title 14, Section 15088.5, before consideration by the Board.

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1. INTRODUCTION

The California Air Resources Board (CARB or Board) released prepared a Draft Environmental Analysis (Draft EA) for the Proposed Amendments to the Low Carbon Fuel Standard (LCFS) and Alternative Diesel Fuel (ADF) Regulations (Proposed Amendments). CARB included this Draft EA as Appendix D to the Initial Statement of Reasons (ISOR). Pursuant to court direction in the modified writ of mandate issued by the Fresno County Superior Court (Superior Court) in POET, LLC v. California Air Resources Board on October 18, 2017 related to CARB's prior CEQA analysis for the LCFS, CARB also prepared a Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation included as Appendix G to the ISOR. The ISOR and appendices (including Appendix D and Appendix G), were released for public review on March 9, 2018. The public comment period for all documents concluded on April 23, 2018.

CARB received numerous comment letters through the docket opened for the Proposed Amendments to the LCFS and ADF Regulations during that time. Comments are available on the CARB website at: https://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=lcfs18. Pursuant to CARB's certified regulatory program, staff carefully reviewed all the comment letters received to determine which ones raised significant environmental issues related to the EA requiring a written response.

This document presents those comments and CARB staff's written responses for the Board to consider for approval prior to taking final action on the Proposed Amendments. Although this document includes written responses only to those comments related to the Draft EA and/or Appendix G, all of the public comments were considered by staff and provided to the Board members for their consideration. The full comment letters are reproduced before each set of responses. For reference purposes, this document includes a summary of each comment followed by the written response. Attachments and appendices to these comment letters can be found at the link provided above.

Following consideration of the comments received on the Draft EA and during the preparation of the responses to those comments, CARB revised the Draft EA to prepare the Final EA released September 17, 2018. CARB also revised Appendix G and released a final version of that document (Final NOx Disclosure Document) on September 17, 2018.

A. Requirements for Responses to Comments

These written responses to public comments on the Draft EA are prepared in accordance with CARB's certified regulatory program to comply with the California Environmental Quality Act (CEQA). CARB's certified regulations states:

> *California Code of Regulations, title 17 section 60007. Response to Environmental Assessment*

> *(a) If comments are received during the evaluation process which raise significant environmental issues associated with the proposed action, the staff shall summarize and respond to the comments either orally or in a supplemental written report. Prior to taking final action on any proposal which significant environmental issues have been raised, the decision maker shall approve a written response to each such issue.*

Public Resources Code (PRC) Section 21091 also provides direction regarding the consideration and response to public comments under CEQA. While the provisions refer to environmental impact reports, proposed negative declarations, and mitigated negative declarations, rather than an EA, this section of CEQA contains useful guidance for preparation of a thorough and meaningful response to comments.

PRC Section 21091, subdivision (d) states:

> *(1) The lead agency shall consider comments it receives … if those comments are received within the public review period.*
>
> *(2) (A) With respect to the consideration of comments received …, the lead agency shall evaluate comments on environmental issues that are received from persons who have reviewed the draft and shall prepare a written response pursuant to subparagraph (B). The lead agency may also respond to comments that are received after the close of the public review period.*
>
> *(B) The written response shall describe the disposition of each significant environmental issue that is raised by commenters. The responses shall be prepared consistent with section 15088 of Title 14 of the California Code of Regulations, as those regulations existed on June 1, 1993.*

California Code of Regulations, title 14, section 15088 (CEQA Guidelines) also include useful information and guidance for the preparation of a thorough and meaningful response to comments. It states, in relevant part, that specific comments and suggestions about the environmental analysis that are at variance from the lead agency's position must be addressed in detail with reasons why specific comments and suggestions were not accepted. Responses must reflect a good faith, reasoned analysis of the comments.

> *California Code of Regulations, title 14, section 15088 (a – c) states:*
>
> *(a) The lead agency shall evaluate comments on environmental issues received from persons who reviewed the draft EIR and shall prepare a written response. The Lead Agency shall respond to comments received during the noticed comment period and any extensions and may respond to late comments.*
>
> *(b) The lead agency shall provide a written proposed response to a public agency on comments made by that public agency at least 10 days prior to certifying an environmental impact report.*

> *(c) The written response shall describe the disposition of significant environmental issues raised (e.g., revisions to the proposed project to mitigate anticipated impacts or objections). In particular, the major environmental issues raised when the Lead Agency's position is at variance with recommendations and objections raised in the comments must be addressed in detail giving reasons why specific comments and suggestions were not accepted. There must be good faith, reasoned analysis in response. Conclusory statements unsupported by factual information will not suffice.*

B. Comments Requiring Substantive Responses

CARB is required to prepare substantive responses only to those comments that raise "significant environmental issues" associated with the proposed action as required by California Code of Regulations, title 17, section 60007(a). As stated above, of the total 292 comment letters submitted on the comment docket for the Proposed Amendments and Revisions to the Proposed Amendments, staff determined that 20 of the letters mentioned or raised an issue related to the Draft EA or an environmental issue discussed in the Draft EA. Staff was conservatively inclusive in determining which letters warranted a written response, as many letters raised policy critiques that do not explicitly address the Draft EA. Thus, a response in this document does not concede that any particular comment is relevant to CEQA's requirements, but is instead reflects CARB's efforts to maximize transparency.

Public comments on the Proposed Amendments submitted prior to the Board's second hearing are available on CARB's website at: https://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=lcfs18. Comments on the Draft EA were considered by staff and provided to the Board members for their consideration.

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2. RESPONSES TO COMMENTS

The comment letters were coded by the order and the comment period in which they were received, along with the name of the commenting organization or individual.

Table 2-1 Comment Letter Codes	
Comment Code	**Comment Period Received**
OP, for original proposal	Comments received during the 45-day comment period of the original proposal, March 9 – April 23, 2018
B, for Board hearing written comments	Comments received as written materials during the board hearing, April 27, 2018
T, for testimony at the Board hearing	Comments received as testimony at the Board hearing, April 27, 2018
FF, for first fifteen-day review	Comments received during the first 15-day comment period June 20 – July 5, 2018 for LCFS
SF, for second fifteen-day review	Comments received during the second 15-day comment period August 13 – 30, 2018 for LCFS

The California Air Resources Board (CARB or Board) received 20 comment letters that relate to the Draft Environmental Analysis (Draft EA), the Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation (Appendix G of the Initial Statement of Reasons (ISOR))[1] or an environmental issue, as listed in Table 2-2. Comment letters have been reproduced and bracketed to demarcate specific issues and to allow for thorough responses. Responses are limited to comments that raise substantial environmental points, as required by California Code of Regulations, title 17, Section 60007(a). That is, responses to comments that do not pertain to the content of the Draft EA are not provided in this document. All comment letters received on the Proposed Amendments are available for review at https://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=lcfs18.

[1] Staff prepared Appendix G of the ISOR in response to writ of mandate (writ) issued by the Fresno County Superior Court on October 18, 2017. The writ requires CARB to evaluate whether the original and 2015 LCFS regulations are likely to have caused an increase in biodiesel-related NOx emissions in the past or is likely to cause an increase in the future.

Table 2-2
List of Commenters

Comment Letter Code	Commenter	Affiliation
CAF1_9	Patrick McDuff	California Fueling
INNOSPEC1_51	David Jones	Innospec Inc.
SUNPOWER1_70	Blair Swezey	Sunpower
NRDC1_81	Simon Mui	NRDC
AJFP1_102	Graham Noyes	AJF Producers
RCM1_114	Mark Moser	RCM International, LLC
NEXTGEN1_124	Colin Murphy Ph.D.	NextGen California
GROWTHENERGY1_B4	Chris Bliley	Growth Energy
ECOENGINEERS1_B5	John Sens	EcoEngineers
STI1_B7	Douglas Eisinger	Sonoma Technology
UCLA1_B8	Sean Hecht	UCLA
CAF2_FF2	Patrick J, McDuff	California Fueling
NBBCABA3_FF4	Jennifer Case and Shelby Neal	California Advanced Biofuels Alliance and National Biodiesel Board
FHR2_FF9	Phillip Guillemette	Flint Hills Resources
UNICA3_FF38	Leticia Phillips	Unica
CRF2_FF42	Tim Morillo	Calgren Renewable Fuels
GROWTHENERGY2_FF56	Chris Bliley	Growth Energy
CAF3_SF14	Patrick J. McDuff	California Fueling
CCAALACVAQ1_SF16	Bill Magavern Will Barrett Dolores Barajas-Weller	Coalition for Clean Air American Lung Association Central Valley Air Quality Coalition
GROWTHENERGY3_SF31	Chris Bliley	Growth Energy

Comment Letter CAF1_9 Responses

9-2 The commenter suggests that CARB should use updated market information, specifically regarding the increased availability of lower cost NOx mitigation additives and formulations for biodiesel blends, in its assessment of Alternative 3 in Appendix G of the ISOR.[2] The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Staff did use the most up to date information available to analyze that specific alternative and other alternatives in Appendix G. That information supported the conclusion that even with low cost mitigation available, Alternative 3 would not fully eliminate the possibility of potentially significant local NOx effects, and would reduce statewide PM benefits and reduce statewide health benefits. Although the alternative may accelerate the timeframe of NOx emissions benefits compared to the proposed ADF Regulation, it would do so at an unreasonable cost, in a way that may not be technically feasible, and would be unnecessarily strict.

9-3 The commenter states that a multitude of market factors should be considered when evaluating the economics of biodiesel versus renewable diesel, and that it is not accurate to assume that the cost of biodiesel additives would make biodiesel uneconomical relative to renewable diesel. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. The commenter also states that it is not accurate that Alternative 3 would be counterproductive to carbon intensity (CI) and greenhouse gas (GHG) benefits. As explained in Alternative 3 in Appendix G of the ISOR, despite the availability of low cost mitigation additives and formulations, this alternative would still likely result in a cost increase for all biodiesel blends above B5 relative to the project scenario (i.e., the original and the 2015 LCFS regulations). Any cost increases for biodiesel blends above B5 would likely result in less biodiesel consumption for these blends, and greater quantities of other, more expensive fuels, such as renewable diesel, would likely be necessary to replace credits that would otherwise be generated by biodiesel. There are a variety of factors at play but it stills holds true that the requirement for NOx mitigation will increase costs for biodiesel and that cost is not imposed on other fuels. Therefore, this alternative would make it more difficult and expensive to generate the average carbon intensity reductions

[2] CARB. 2018. Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation. March 6.

and GHG benefits associated with project. Please see response to comment 9-2 regarding the availability of lower cost NOx mitigation options.

9-4 The commenter states that NOx mitigation additives would not impact biodiesel plant construction because of spare capacity currently and that NOx mitigation additive plants would not be built in California. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Staff disagrees with this assessment. As shown in CARB's Illustrative Compliance Scenario Calculator,[3] staff's projections show biodiesel usage within California will nearly triple (from about 170 million gallons to 500 million gallons) from 2017 to 2023 for the project scenario. Based on this projected increase in biodiesel usage in California, increases in both in-state and out-of-state production capacity may be needed with accompanying increases in NOx mitigation additive production plants. Thus, staff conservatively assumed that new or existing plants may need to be constructed or modified to address the projected increased biodiesel and additive demand.

9-5 The commenter suggests that the requirement for NOx mitigation additives would not reduce biodiesel use. The comment does not identify adverse environmental impacts resulting from the proposed project. A CEQA analysis must identify and focus on the "significant environmental effects" of the Proposed Amendments. (Pub. Resources Code § 21100(b)(1); 14 CCR § 15126(a), 15143.) A significant effect on the environment is defined as "a substantial, or potentially substantial, *adverse change* in the environment." (Pub. Resources Code § 21068 [italics added].) A proposed project that foregoes potential benefits, but causes no significant increase in emissions above the environmental baseline, is not a CEQA impact because the project does nothing to adversely change the existing environmental conditions. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. The commenter also believes that the use of NOx reducing additives would improve PM emissions. As discussed in Section F.3.c of the Final NOx Disclosure Discussion, staff believes that biodiesel consumption could decrease under Alternative 3 (due to higher biodiesel prices), and that PM emissions reductions could also decrease, as biodiesel use results in large PM reductions when compared to conventional diesel. In addition, certification testing results for NOx mitigation have shown similar PM reductions for biodiesel blends with and without NOx mitigation.

9-6 The commenter states that biodiesel use could be increased if CARB required NOx mitigation in all biodiesel blends due to the logistics of biodiesel blending

[3] CARB. 2018. Illustrative Compliance Scenario Calculator. August 15. Available at: https://www.arb.ca.gov/fuels/lcfs/2018-0815_illustrative_compliance_scenario_calc.xlsx

mechanisms. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Staff disagrees with the commenter based on observations of current market dynamics and stakeholder discussions. However, staff will continue to monitor the use trends of biodiesel, and will continue to discuss biodiesel logistics with stakeholders moving forward and will take appropriate action based on those observations. CARB is not currently considering changing the NOx control levels in the ADF regulation.

9-7 The commenter states that the lack of additive infrastructure is a critical hurdle increasing use of biodiesel blends, and suggests that removal of season allowances could help to overcome this hurdle. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Please see response to comment 9-6 related to comments on potential removal of infrastructure barriers.

9-8 The commenter states that removal of seasonal allowances is unlikely to cause terminals to move away from biodiesel blending because many regulated parties rely on B5 blends to generate LCFS credits. Please see response to comment 9-6 related to comments on potential removal of infrastructure barriers.

9-9 The commenter states that the dial down NOx mitigation treat rates would ensure that when blending B5 to B10, such blends would only incur a minimal additive treat cost expense (one quarter to one half that of B20). Please see response to comment 9-2 related to increased costs for biodiesel blends and response to comment 9-6 related consideration of changing NOx control levels in the ADF regulation.

Comment Letter INNOSPEC1_51 Response

51-1 The commenter suggests that additives certified under the ADF regulation be reviewed if they were tested using a reference fuel with more than 1.4 percent polycyclic aromatic hydrocarbon (PAH) content. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. The ADF regulation as approved in 2015 included a maximum PAH content of 10 percent for the reference CARB diesel, and ADF certifications were issued to companies that demonstrated the emissions equivalency based on the 2015 approved ADF regulation. CARB staff subsequently updated the ADF frequently asked questions document to clarify that the maximum PAH content of 10 percent was a typo that should have read 1.4 percent. The amendments to the ADF analyzed by the Draft EA included a proposed correction of this typographical error.

Comment Letter SUNPOWER1_70 Response

70-4 The commenter agrees with previously submitted feedback by Center for Resource Solutions (CRS) during the informal pre-rulemaking period highlighting the importance of verification using established REC accounting principles to safeguard against double counting of the environmental attributes associated with the uses of renewable energy. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Staff appreciates stakeholder's comment, which is consistent with the proposed regulation language in section 95488.10(a)(4), "Additionally, for any electricity that is used to reduce carbon intensity of electricity used as a transportation fuel or hydrogen production via electrolysis, the pathway holder must upload records demonstrating that any renewable energy certificates generated were retired in WREGIS for the purpose of LCFS credit generation."

Comment Letter NRDC1_81 Responses

81-14 The commenter supports the CEQA analysis of the LCFS and ADF rules as being conservative. Staff appreciates this support.

81-15 The commenter states that the focus on biodiesel by itself provides only a narrow and limited view of the LCFS in its entirely in terms of impacts on emissions and to public health.

Staff agrees with the commenter's statement that the environmental and public health impacts of biodiesel, considered by itself, do not provide a full picture of the impacts of the LCFS regulation as a whole. Staff also agrees with the commenter's statement that the LCFS program is expected to reduce criteria air pollutant (CAP) emissions statewide, including NOx and PM, by substituting cleaner fuels for petroleum-based fuels, and that the ADF regulation combined with the LCFS result in even lower NOx emissions than if there were no LCFS program. For additional details see Attachment H to the Second Notice of Public Availability of Modified Text and the Final EA's discussion of impacts on air quality.

That said, staff has closely examined the NOx impacts of LCFS-attributed biomass-based diesel per court direction, under both the original and 2015 LCFS regulations. As explained in Appendix G of the ISOR and the Final Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation ("Final NOx Disclosure Discussion"), to address court direction, CARB's supplemental disclosure discussion of potential NOx impacts related to the LCFS regulation focused on the potential impacts of biodiesel and renewable diesel use in California.

Comment Letter AJFP1_102 Response

102-13 The commenter supports CARB’s conclusion in the Draft Environmental Analysis. Staff appreciates the support of CARB’s conclusion in the Draft Environmental Analysis that without the use of alternative jet fuels (AJFs), it could be difficult to achieve long-term GHG emission reduction goals in the State, and that the likely outcome of the Proposed Amendments’ inclusion of AJF is that the total air quality benefits of the regulation will increase. As the commenter mentions, independent analysis by NREL and ACRP confirm the reduction in criteria pollutant emissions from use of AJF.

Comment Letter RCM1_114 Response

114-1 The commenter suggests that hauling manure by truck to ethanol plants would create more greenhouse gas emissions and additional road traffic as well as diesel exhaust emissions, proposing that staff consider adding an option for "transmitting manure by wire" in order to avoid such emissions. Staff does not consider hauling manure by truck to ethanol plants to be a reasonably foreseeable compliance response to the Proposed Amendments.

The Proposed Amendments recognize the use of biomethane (including biomethane produced from manure) that is supplied through the common carrier natural gas pipeline for the following end uses: as CNG or LNG in a natural gas vehicle; to produce hydrogen that is used in a fuel cell vehicle; to produce hydrogen that is used in the production of a transportation fuel, e.g., a petroleum refinery or for hydrotreating at a biorefinery. These options are considered to be much more financially viable uses for biomethane produced from manure that would not require hauling manure by truck. In some locations, where an ethanol plant is located near to a source of biomethane feedstock such as manure, there are several more economically rational options that would be eligible for LCFS recognition of the use of biomethane as process energy at a biofuel production facility, including transmission of biogas or biomethane by direct pipeline to the facility. As the commenter points out, producers who ship distiller's grains to feed lots by truck could transport manure back to a digester at the ethanol plant on the return trip; in this scenario there would be negligible emissions attributable to the manure transport because there are no additional trips.

Comment Letter NEXTGEN1_124 Response

124-50 The commenter states that indirect effects of fuel production, especially indirect land use change (ILUC), can result in significant emissions, suggesting that that the literature on indirect effects is far from complete and that a possibility that the current iLUC values used by the LCFS substantially underestimate actual effects cannot be ruled out. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure regarding the LCFS approach to ILUC, see response to comment B4-20.

Comment Letter GROWTHENERGY1_B4 Responses

B4-1 The commenter states that it supports CARB's mitigation of estimated historical NOx emissions that were incentivized by the LCFS program and the funding of local projects in the geography areas most directly affected by such increased NOx emissions. Staff appreciates the support for CARB's measure to remediate estimated historical oxides of nitrogen (NO_X) emissions increases associated with biomass-based diesel use that may have been incented by the LCFS.

B4-2 The commenter states that the remediation measure identified in Appendix G of the ISOR should be considered concurrently with the rulemaking process for the amendments. As discussed in Section D.4.a of the Final NOx Disclosure Discussion, the Voluntary NOx Remediation Measure (VNRM) referred to by the commenter is not an amendment to the LCFS or ADF regulations, nor is it identified as mitigation for the Proposed Amendments. Rather, the VNRM is an additional initiative designed to address potential LCFS-attributed biomass based diesel NOx emissions increases in a few historical years. Taking a conservative approach, the measure does not discount for historical years in which there may have been a decrease in LCFS-attributed biomass-based diesel NOx emissions. The VNRM was presented to the Board along with the proposed amendments to the LCFS and ADF regulations during the April 27, 2018 Board Hearing. The Board approved Resolution 18-22, authorizing implementation of the VNRM, as set forth in Attachment A to Resolution 18-22.

B4-3 The commenter states that key questions should be answered before CARB considers the VNRM item. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. A staff report is not required for the VNRM; however, background for the VNRM can be found in Section D.4.a of the Final NOx Disclosure Discussion[4] with additional detail in Attachment A of Resolution 18-22,[5] which addresses most of the commenter's questions. Resolution 18-22 was approved by the Board on April 27, 2018. Answers to the commenter's specific questions are provided below:

- CARB will voluntarily remediate up to 743 tons of NOx through the VNRM grants. This represents the estimated cumulative NOx

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[4] CARB. 2018. Final Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation. September 14.

[5] CARB. 2018. Resolution 18-22, Attachment A – Voluntary NOx Remediation Measure Funding Guidelines for District Grants to Remediate Potential Historic Biodiesel NOx Emissions Conservatively Attributable to the LCFS. April 27.

emissions increases over all historical years (2007 – 2017) from LCFS-incented biomass-based diesel, considering only years with increases and none of those with decreases. Staff notes that there was a net cumulative increase in NOx emissions from LCFS-attributed biodiesel of 58 tons during the historical period, 2007 – 2017.

- Local projects will be selected by participating air districts following the procedures in the Carl Moyer Program (CMP) Guidelines, subject to the variations discussed in Attachment A of Resolution 18-22 and the Memoranda of Agreement (MOA) between individual air districts and CARB.
- CARB will confirm that selected local projects will reduce NOx emissions through tracking of project NOx emissions reductions using the Clean Air Reporting Log (CARL).
- CARB worked with the California Air Pollution Control Officers' Association (CAPCOA) to develop an initial funding allocation. Under the initial allocation, funds were allocated to individual air districts based on the estimated percentage of the total historical NOx emissions driven by LCFS-incented biomass-based diesel use that were likely to have occurred in each air district, as shown in Table 1 of Attachment A to Resolution 18-22. The VNRM NOx reductions would occur in the same general geographic areas that the estimated NOx increases were likely to have occurred.
- Funding for VNRM grants, originally estimated at $4.5 million for fiscal year 2017-18, was from CARB's Air Pollution Control Fund (APCF). Seventeen of the 35 California air districts accepted the initial proposed funding allocation, and an additional five air districts, deferred their allocations to specific participating air districts. Combined, these districts account for approximately 95 percent of the cumulative historical NOx emissions from LCFS-incented biomass-based diesel. The remaining funds were reallocated to participating air districts following the methodology used for the initial allocation. Grant agreements for the 17 participating air districts were executed by June 22, 2018.
- An additional $4.5 million in funding from the APCF became available prior to the end of FY 2017-2018. Amended grant agreements for all 17 participating air districts were executed by June 28, 2018, bringing the total funding allocation to $9 million, the estimated funding level needed to achieve full remediation of historical NOx emissions increases due to biomass-based diesel use, based on an assumed cost-effectiveness of $10,000 per ton of NOx emissions reduced. A summary of the air district's responses to the grant funding solicitation, and the updated funding allocation associated with the original and

amended grant agreements is available in the Final NOx Disclosure Discussion.

- As indicated in Attachment A of Resolution 18-22, CARB estimated a total of $9 million to $18 million is needed for full remediation, based on a cost-effectiveness of $10,000 to $20,000 per ton of NOx emissions reduced, respectively. These estimates are based on the estimated range of NOx-only cost-effectiveness values for CMP projects. If the committed funds are not sufficient to remediate potential historical NOx emissions increases due to biomass-based diesel use attributed to the LCFS, CARB may increase available funding for VNRM grants.
- CARB will make publicly available the expenditures it makes under the VNRM grants.
- Eligible projects under the VNRM are limited to retrofit or replacement of: on-road trucks, off-road equipment, agricultural equipment, and marine equipment and locomotives. Biodiesel use primarily occurs in these types of equipment. Eligible projects must reduce NOx, and those reductions must be permanent, surplus, and quantifiable.
- Projects will be implemented by the air districts and air district-selected grantees following the guidelines and requirements in Attachment A of Resolution 18-22 and the MOAs between individual air districts and CARB. Implementation of VNRM grant funding and tracking of NOx emissions reductions will generally follow the CMP Guidelines. A high-level summary outlining the criteria and administrative requirements for implementation of VNRM that differ from those in the CMP Guidelines is provided in Attachment A of Resolution 18-22.

B4-11 The commenter provides a summary of issues pertaining to CEQA. See responses to comments B4-35 through B4-58.

B4-12 The commenter suggests that the Proposed Amendments are not consistent with a purported AB 32 statutory requirement “to prevent any increase in the emissions of … criteria pollutants.” See response to B4-33.

B4-13 The commenter lists examples of the California Administrative Procedure Act (APA) requirements related to the adoption of regulations. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Alternatives subject to CEQA requirements are provided in Section 7, Alternatives Analysis in the Draft EA.

B4-14 The commenter correctly states that the Western States Petroleum Association (WSPA) submitted an alternative that was dismissed in the ISOR and EA documents. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. See response to comment B4-50.

B4-16 The commenter correctly states that a rulemaking file must be made available to the public for inspection. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. As publicly noted on page 25 of the Notice of Public Hearing released March 6, 2018 related to this rulemaking, the rulemaking file was made available for public inspection.

B4-17 The commenter states that CARB must commission peer reviewers to evaluate the scientific portions of the rule. This comment does not speak to CEQA compliance issues because the peer review requirement is not required by CEQA and does not relate directly to environmental impact analysis. Moreover, the comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. In connection with the 2015 adoption of the LCFS and ADF regulations, CARB contracted with a group of four researchers to perform a LCFS regulation peer review and with a group of seven researchers to perform an ADF regulation peer review consistent with the requirements of Health and Safety Code section 57004. These peer reviewers were chosen by the University of California via the Cal/EPA Scientific Peer Program, through which the Office of the President carries out its responsibility under section 57004 to recommend scientists or groups of scientists to conduct peer reviews. Because the fundamental scientific bases of the health protective standards and methodological framework underlying both regulations that remained unchanged by this amendment rulemaking were peer reviewed during that initial adoption, further peer review is not required.

B4-18 The commenter states that CARB must identify the environmental effects of the project and provide feasible mitigation measures to reduce the significant environmental impacts. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows.

Chapter 4 of the Draft EA provides an evaluation of the environmental effects of the Proposed Amendments and offers mitigation measures where appropriate which, when implemented by a lead agency, could reduce the severity of significant environment effects. This comment contains no specific issues for which a further response is required.

B4-19 The commenter states that CARB's certified regulatory program, in compliance with CEQA, requires a functional equivalent document that includes alternatives and mitigation measures. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Chapter 4 of the Draft EA provides an analysis of the environmental effects of the Proposed Amendments and offers mitigation measures which, if implemented by a lead agency, could reduce the severity of significant impacts. Chapter 7 provides a description and analysis of five alternatives to the Proposed Amendments, and a discussion of an additional alternative that was considered but determined to not be feasible.

As noted by the commenter, comments raising significant environmental issues must be responded to before approval of the document is considered. This document provides responses to all substantive environmental comments, as well as responses to many comments that are not substantive environmental comments in the interest of comprehensive disclosure.

B4-20 The commenter highlights a 2009 witness statement related to uncertainty in indirect land use change (ILUC) values for crop-based biofuels. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. ILUC values published in the 2009 ISOR and subsequently updated in 2015 reflect values for such impacts using the best available economic and scientific information. The ILUC analysis was supported by a comprehensive peer review both in 2009 and 2015. To specifically consider the likelihood of uncertainty in estimated values, a Monte Carlo analysis was performed and an average value based on probability distribution of expected values was considered in the 2015 update. Staff did not change the ILUC values and is confident that current ILUC values are estimated using best available information and appropriately attribute emissions to crop-derived biofuels. Future regulatory updates will consider advances in the science of land use change and update ILUC values accordingly, should such changes be necessary.

As for CA-GREET3.0 updates, the current amendments reflect the most current information related to lifecycle data for crop farming, fertilizers, emission factors, truck payload and other inputs. These have been derived from the GREET1_2016 version of Argonne National Laboratory (ANL). This version represents the latest version available when updates were being developed to create CA-GREET3.0. The lifecycle analysis for direct emissions for all transportation fuels use the updated factors and methodologies embedded in CA-GREET3.0 to calculate the CIs for all transportation fuels and reflect the use of the best available data. The fundamental science used to derive these values has not changed since the most recent peer review was conducted. However, new information has been incorporated to CA-GREET3.0 through collaboration with outside experts (including those at ANL), through staff's expert judgement, and using information supplied during the stakeholder comment process.

B4-21 The commenter states that the "signals" that CARB's new CA-GREET3.0 model and ILUC models for corn-starch, corn-stover, sugarcane ethanol, and electricity do not reflect the best available scientific and economic information and do not provide the "signals" to the downstream industry needed to maximize reductions in GHG emissions while minimizing costs. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. See response to comment B4-20.

Staff continues to conduct a robust and transparent public review of the modeling tools used in the calculations of fuel pathway carbon intensities, and continues to address feedback as required by the APA. Specific comments regarding inputs to modeling tools or life cycle analysis approaches are addressed individually as part of the Final Statement of Reasons (FSOR) and are available as part of the public record.

B4-22 The commenter reiterates a concern it has raised since 2009 that an LCFS policy in California might drive fuel shuffling. These policy critiques are not well supported and do not concern the adequacy of the draft EA. In support of its renewed concern, the commenter submits consultant analysis commissioned by the commenter concluding that ethanol producer POET has strategically chosen to implement a fuel shuffling compliance response to the LCFS, rather than taking steps to lower the carbon intensity of its products company wide.

Aside from POET, LLC., many other fuel producers have demonstrated initiatives to CARB in recent years to increase production of low-CI fuels and reduce the CI of the fuel produced for sale in California. The scope and scale of these investments and process changes have been well-documented in the press and observed by CARB. But even assuming that a fuel producer might simply shuffle fuel, based on substantial evidence supporting the program and this record, CARB staff continues to believe that fuel shuffling is not an expected long-term market response to an increased and growing demand for a low carbon fuel in California and other jurisdictions. Based on the evidence, including a steady pace of new facilities and production changes throughout the market, suppliers of credit generating fuels to California are responding to the LCFS primarily by implementing measures to decrease the CI of their fuels, and increasing production of low carbon fuel. Particularly as the LCFS benchmarks become more stringent post-2030 pursuant to the Proposed Amendments, to the extent fuel shuffling occurs, it is expected to be limited in amount and duration, and not at a magnitude sufficient to undermine the benefits of the LCFS.

Without the commenter providing more detailed supporting information, CARB staff are unable to verify the commenter's consultant's conclusion that POET's fuel delivery reorganization in response to the LCFS "likely has generated additional carbon emissions." Even if that conclusion were verified as accurate, the evidence, and the increasingly stringent design of the LCFS, overwhelmingly supports CARB staff's determination that the LCFS as structured functions to spur production and use of low CI fuels, reducing the lifecycle GHG emissions of the California fuel pool. The evidence suggests that along with other similar policies at the federal level and in other jurisdictions such as Oregon and British Columbia, the LCFS is working and will continue to work to drive down the carbon intensity of transportation fuel supply beyond California's borders. To the extent that POET has predominantly prioritized a delivery reorganization compliance strategy with respect to the LCFS, rather than the desired strategy of new investment to lower the CI of their total supply chain, the evidence before CARB staff suggests that such a strategy will not be a tenable source of sufficient low carbon fuel to meet long-term CI reductions called for by the Proposed Amendments.

B4-23a The commenter suggests that a distillers' grains methane credit should be included in CA-GREET3.0 for LCFS ethanol pathways because the animals consuming distillers grain with solubles (DGS) should be included in the LCFS life cycle assessment (LCA) ethanol system boundary. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. The California-specific CA-GREET3.0 only uses Argonne's GREET1_2016 as the LCA modeling framework and incorporates appropriate modifications that are consistent with the current/proposed LCFS regulations. There is no credit for reduced enteric fermentation emissions due to the inclusion of DGS in livestock rations in LCFS ethanol pathways.

The animals consuming the DGS are not currently within the LCFS LCA ethanol system boundary. Including the feeding of animals in the LCA would require a comprehensive analysis by considering life cycle impacts of livestock in the LCA of corn ethanol. It would include not only the differences between enteric emissions associated with rations that do and do not include DGS but also emissions associated with those rations. Also, the feed market data would need to be analyzed and updated. The LCFS LCA boundary includes only the feed market changes that occur when DGS is added to livestock rations, e.g. displaced corn, soybean meal, and urea. The uncertainty and complexity involved in accounting for GHG emissions from all affected rations and animals is discussed below.

It is important to consider that reduced enteric emissions result primarily from the shortened lifespans of the animals being fed DGS because they grow faster and spend less time in feedlots than livestock with rations that do not contain DGS. If it is true that cattle fed DGS spend less time in feedlots than do cattle not fed DGS, the effects on total feedlot throughput must be determined. It could be that as DGS decreases per-animal feedlot residence time, it increases the rate at which animals pass through the feedlot. This could mean that enteric emissions per unit of time do not change, relative to pre-DGS conditions. Although enteric emissions per pound of meat produced might decrease, emissions per megajoule (MJ) of fuel produced must be measured (or calculated). If feeding costs per animal decrease, feedlot expansion may also become feasible[6].

The effects of feedlot expansion on emissions per MJ of ethanol must be ascertained. If DGS rations increase cattle throughput (or effectively increase feedlot size), lifecycle enteric emissions per MJ of fuel produced could remain constant or increase. At least one study acknowledges the possibility of feedlot expansion for operations that reduce cattle lifetimes due to the use of ethanol co-product DGS in rations: on pages 912-913 of Arora et al.[7] the authors state, “In Nebraska, the synergies achieved from reduced energy costs for ethanol plants and better performance for beef cattle have resulted in a higher feedlot size for operations that use ethanol co-products.” If this higher feedlot size simply means that the animals weigh more (produce more product) with the same amount of feed (DGS), then there would be excess DGS. If there is excess DGS, then other animals will be fed the excess DGS

[6] Bremer, Virgil R., Adam J. Liska, Terry J. Klopfenstein, Galen E. Erickson, Haishun S. Yang, Daniel T. Walters, and Kenneth G. Cassman. "Emissions savings in the corn-ethanol life cycle from feeding coproducts to livestock." *Journal of environmental quality* 39, no. 2 (2010): 472-482. https://dl.sciencesocieties.org/publications/jeq/abstracts/39/2/472

[7] Arora, Salil, May Wu, and Michael Wang. "Estimated displaced products and ratios of distillers’ co-products from corn ethanol plants and the implications of lifecycle analysis." Biofuels 1, no. 6 (2010): 911-922. https://greet.es.anl.gov/publication-corn-ethanol-displaced-products

resulting in similar lifecycle emissions. If other animals do not eat the excess DGS then it does not enter the market as an ethanol co-product.

Including ruminants on DGS rations in the LCFS LCA system boundary requires that GHG emissions from all animals fed with DGS rather than from only the rumen be included in the fuel lifecycle CI. Accounting only for a reduction in emissions from the rumen excludes other livestock emissions: Including defatted DGS (DGS from which corn oil has been extracted) in beef cattle finishing rations has been shown to cause an increase in N_2O emissions[8] [9]. The same studies also show that the presence of oil in DGS may be responsible for reductions in enteric methane. It implies that defatted DGS may not reduce enteric methane.

These N_2O emissions, and any others caused by inclusion of DGS in rations would have to be accounted for if beef cattle were included in the LCFS ethanol system boundary. Accounting of DGS transportation from the ethanol plants to the animals would also need to be included in the LCA if the animals were within the LCA system boundary. Currently, the ethanol is credited with the upstream emissions for producing the displaced products (e.g., corn, or in CA-GREET3.0, corn, soy meal, and urea) and the transportation of the ethanol feedstock transport to the ethanol plant, but not the transport of the actual DGS to the animals.

Non-ruminant animals are also fed DGS. These animals would presumably not experience reduced methane emissions because of being fed DGS compared to non-DGS. What may occur with these non-ruminant animals when fed greater rations of DGS, with presumably higher overall protein content than the alternative feed, is increased nitrogen excretion. The nitrogen excreted in the form of urea would likely result in greater N_2O emissions seen similarly with finishing beef cattle, but with non-ruminants having no reduction in methane emissions (due to reduced lifetime) to offset some of the nitrogen excretion related emissions. Non-ruminant animals fed DGS and their resulting emissions would need to be considered if the feeding of animals is appropriately accounted for in the LCA of the ethanol and resulting DGS co-product.

[8] Hünerberg, M., S. M. McGinn, K. A. Beauchemin, E. K. Okine, O. M. Harstad, and T. A. McAllister. "Effect of dried distillers' grains with solubles on enteric methane emissions and nitrogen excretion from finishing beef cattle." *Canadian Journal of Animal Science* 93, no. 3 (2013): 373-385. http://pubs.aic.ca/doi/abs/10.4141/cjas2012-151

[9] Hünerberg, Martin, Shannan M. Little, Karen A. Beauchemin, Sean M. McGinn, Don O'Connor, Erasmus K. Okine, Odd M. Harstad, Roland Kröbel, and Tim A. McAllister. "Feeding high concentrations of corn dried distillers' grains decreases methane, but increases nitrous oxide emissions from beef cattle production." *Agricultural Systems* 127 (2014): 19-27. http://www.sciencedirect.com/science/article/pii/S0308521X14000146

The same approach is consistent with the Compliance Offset Protocol Livestock Projects, which excludes animals and associated enteric methane production. The Protocol includes only the avoided methane from manure management which is a first order impact whereas enteric methane avoided due to DGS use is the second order impact in the corn ethanol life cycle. The animal feed displacement is a first order impact accounted in estimating DGS credits.

B4-23b The commenter states that including values for energy use per ton-mile for medium-duty trucks that are lower than those for heavy-duty trucks is not logical, which resulted in CA-GREET3.0 and GREET 2016 having overestimated the fuel use for medium-duty trucks. The commenter also states that CA-GREET3.0 overestimates transportation emissions for heavy-duty trucks. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. After consulting with Argonne's GREET team, staff updated fuel economy for medium- and heavy-duty trucks (both forward and backhaul trips) as well as truck payload for transport of corn, soybean and canola. The CA-GREET3.0 supplemental document provides details of the updated values.

B4-23d The commenter encourages CARB to swiftly consider the approval of proposed pathways for innovative fuels, such as fuels derived from corn fiber, to help provide evidentiary support for CARB's estimate that the CI for corn ethanol will drop from approximately 70 g/MJ to 45 g/MJ. The commenter is also unclear what evidence was relied upon to determine corn ethanol facilities would install carbon capture and sequestration (CCS) systems at the rate necessary to reduce their CI to 45 g/MJ. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Staff will continue to evaluate all fuel pathway applications as they are submitted, pursuant to the process outlined in the Proposed Amendments.

Assuming adoption of the proposed CCS protocol in 2018, staff expects that additional CCS projects at starch ethanol facilities will become operational starting 2021, allowing plants that supply ethanol to California two years to implement CCS projects. According to a study published in the Proceeding of the National Academy of Sciences[10] and staff's internal analysis, most ethanol plants in the United States can implement CCS projects at a value of GHG emissions reductions of \$25 to \$120/tCO_2e. To conduct the illustrative compliance scenario, staff assumed that ethanol plants will implement CCS projects to reduce the ethanol CI by a maximum reduction of 26 g/CO_2e, with higher expected LCFS credit prices leading to more rapid reductions in the ethanol CI according to this assumed schedule:

- An equivalent to a 5 percent reduction in starch ethanol's CI annually if the LCFS price range is \$60 - \$99.
- An equivalent to 7.5 percent reduction in starch ethanol's CI annually if the LCFS credit price range is \$100 - \$150.
- An equivalent to 10 percent reduction in starch ethanol's CI annually if the LCFS credit price is above \$150.

CCS projects have already been implemented at a commercial scale in at least one ethanol biorefinery in the United States. In April 2017, the ADM facility in Decatur, Illinois became the first ethanol plant to deploy commercial scale carbon capture and sequestration. The 350 million gallon per year facility will capture over one million tons CO_2 per year from fermentation and inject the carbon in a saline aquifer below the facility. Additionally, Red Trail Energy is implementing a CCS project at their ethanol biorefinery in North Dakota.[11]

B4-23e The commenter lists issues with how the CI was calculated for sugarcane ethanol using CA-GREET3.0. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Staff has updated the CA-GREET3.0 model to reflect an average value of "N" content from four independent studies (Macedo, Seabra, Lisboa, and Gava et al.)[12] of 0.5275% to reflect higher N content in sugarcane biomass as suggested by the commenter.

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[10] Sanchez et. al, 2018. *Near-term deployment of carbon capture and sequestration from biorefineries in the United States.* http://www.pnas.org/content/pnas/early/2018/04/18/1719695115.full.pdf. Accessed June 29, 2018.
[11] IBID
[12] Macedo, 2007. "Sugar Cane's Energy: Twelve studies on Brazilian sugar cane agribusiness and its sustainability," I.C., UNICA, 2nd ed, 2007.
Seabra et al, 2011. "Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use," Seabra, J., Macedo, I., Chum, H., Faroni, C., Sarto, C., Biofuels, Bioproducts and Biorefining, V5, 519-532, 2011.

The commenter contends that the nitrogen input values in CA-GREET3.0 are understated because they do not include the nitrogen in the roots of the sugarcane crops. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Even though the "N content of above and below ground biomass" parameter is applicable to both above and below ground biomass, staff concurs with the commenter that no amount of below ground biomass was considered to estimate the nitrogen content for this field. In this regard, staff will undertake additional research in collaboration with ANL to further determine the correct amount of N_2O released by below ground sugarcane biomass for the next model update.

The commenter cites the Virtual Sugarcane Biorefinery (VSB) model to argue that CA-GREET3.0 underestimates the nitrogen fertilizer input (nitrogen levels) per tonne of sugarcane biomass. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Staff has reviewed other studies, including Wang et al. (2012)[13] and Seabra et al (2011)[14], and has come to the conclusion that the existing nitrogen fertilizer input value is a reasonable and accurate estimate.

B4-23f The commenter states that there are several errors in the existing Tier 1 simplified calculators. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Specific comments regarding inputs to modeling tools or life cycle analysis are addressed individually as part of responses to the comments from this commenter.

B4-23g The commenter states that deferral of the above issues to a later proceeding would not comply with Assembly Bill (AB) 32 or CEQA, as it would defer

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Lisboa et al, 2011. "Bioethanol production from sugarcane and emissions of greenhouse gases – known and unknowns," Lisboa, C.C., Butterbach-Bahl, K., Mauder, M., Kiese, R., GCB Bioenergy 3, 277-292, 2011.
Gava et al, 2005. "Urea and sugarcane straw nitrogen balance in a soil-sugarcane crop system," Gava, G.J. de C., Trivelin, P.C.O., Vitti, A.C., Oliveira, M.W. de, Pesquisa Agropecuaria Brasileira, 40, 689-695, 2005.

[13] Michael Wang et al, 2012 Environ. Res. Lett. 7 045905.

[14] Seabra, J.E.A. et al, 2011. "Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use,"

analysis and mitigation, and the consideration of feasible alternatives. As the responses above indicate, CARB has not deferred analysis of any of the issues raised by this commenter. Indeed, CARB has made some changes in response to those comments and has explained why other changes are not warranted. Further, none of these issues raised by the commenter identify environmental impacts of the project, so it is incorrect to suggest that CARB is deferring mitigation of any impacts. Rather, these issues constitute the commenter's disagreement with reasonable and supported assumptions made by CARB, and CARB has explained the basis of its disagreement with the commenter.

B4-24 The commenter asserts that staff has ignored efforts by stakeholders to improve the quality of CARB's ILUC and indirect-emissions models, as well as recommendations of the Expert Working Group (EWG). The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. This is not the case. CARB conducted an extensive public process between 2012 and 2015 to update ILUC values for biofuels. The update utilized best available economic and scientific information and resulted in revisions to ILUC values from the original values published in 2009.

Several updates to reflect feedback from the EWG were incorporated into the model. The database was updated to reflect 2004 data in the GTAP model. A separate carbon emissions model called the Agro-Ecological Zone-Emissions Factor was developed and used in combination with the GTAP model to account for advances in soil carbon data and science. In addition to GTAP results, an uncertainty analysis using a Monte Carlo framework was used to corroborate GTAP model outputs. The results from the updated ILUC analysis was also subject to a peer-review by experts in this field.

The commenter directs attention to an updated GTAP model available in 2017 and questions why CARB did not consider updates to ILUC analysis for the current rulemaking. Completing a comprehensive review of updated data and land use science coupled with an extensive public process to inform stakeholders of changes to the modeling framework is likely to require between 36 and 48 months. The consideration of using the updated July 2017 model referenced by the commenter would significantly delay the current rulemaking process. However, staff maintains its commitment to accurate assessment of land use change emissions. At a future date, staff will review updates to relevant models and will review suggested modifications by the EWG, conduct extensive stakeholder interactions and refine ILUC values for all crop-based biofuels. The reference to 2011 data is not relevant since it was not considered in the 2015 update to LUC analysis.

B4-25a The commenter suggests corrections when developing the energy economy ratios (EERs) for heavy-duty electric vehicles. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. When developing the EERs for heavy-duty electric vehicles, staff relied upon all available studies and information for commercially-available vehicles, including chassis dynamometer studies as well as real world test studies. The results from both kinds of studies were found to be consistent in terms of fuel economies. Therefore, the EERs developed by staff were based on real world testing as well. Staff will continue to re-evaluate and update the EER values as more fuel efficiency studies become available.

B4-25b Staff disagrees with the commenter that efficiency for conventional gasoline and diesel are understated. When comparing fuel efficiencies, staff relied upon the most recent models of conventional vehicles to reflect the fuel efficiency improvements of the gasoline and diesel vehicles.

B4-25c The commenter suggests corrections when developing the EERs for compressed natural gas (CNG) and propane engines. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. As stated in Appendix H of the ISOR, the studies staff used to develop CNG and propane EERs provided a comparison between energy usage from propane/CNG trucks/buses and diesel trucks/buses operated under identical duty cycles. Both propane/CNG vehicles and diesel vehicles must operate with their tanks when comparing their energy usage under identical duty cycles. Therefore, the weights of tanks were accounted for and not excluded in the EER development.

B4-25d The commenter states that staff did not consider modifications to the EER required to accurately characterize electric drivetrain and battery losses. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. The methodology used for EER development under the LCFS program is solely a comparison of vehicle fuel efficiencies under the same duty cycles. When developing EERs for all fuel-vehicle combinations, staff included all available studies and data. Moving forward, if more detailed fuel economy studies that better characterizes the electric drivetrain and battery losses become available, staff commits to revisit and update the EER values accordingly.

B4-25e The commenter states that because accessory loads are not switched on during dynamometer testing and increased loads on the battery makes it less efficient, the EERs for electric vehicles are underestimated. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. When developing the EERs for heavy-duty electric vehicles, staff relied upon all relevant studies and information available for commercially-available vehicles, including chassis dynamometer studies as well as real world test studies. The results from both kinds of studies were found to be consistent in terms of fuel economies. Therefore, the EERs developed by staff were based on real world testing as well, in which the accessory loads were switched on. Staff commits to re-evaluate and update applicable EER values as more fuel efficiency studies become available that include accessory loads.

B4-25f The commenter states that the EER for fuel cell vehicles is overestimated. The provided comments are out of scope for this rulemaking because the modifications discussed in the comment were not incorporated in the proposed revisions or included in the notice of changes.

B4-25g The commenter suggests corrections when developing the EERs for electric trucks and buses. See response to comment B4-25a.

B4-25h The commenter states that the EER for transport refrigeration units is overestimated. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. As stated in Appendix H of the ISOR, there is limited data available for the development of EER for electric Transportation Units (eTRUs). Staff recommended a conservative value based on available data. Staff commits to re-evaluate and update the eTRU EER value as more relevant studies, such as those mentioned in Appendix H of the ISOR, become available.

B4-25i The commenter suggests corrections when developing the EERs for electric motorcycles. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. As stated in Appendix H of the ISOR, staff acknowledges that a truly representative EER would be based on data collected over multiple drive cycles representing real world operating conditions. To account for the possible difference between the efficiency achieved in the test cycle as compared to that likely to be achieved in real world usage, staff discounted the initial EERs by a factor of 0.5. This conservative EER value will incentivize the emission reduction from the use of electric motorcycles until a more comprehensive data set of motorcycle efficiencies under various operating conditions can be collected and analyzed. Staff commits to re-evaluate and update the e-motorcycle EER value as more fuel efficiency studies become available.

B4-25k The commenter also states that the CI values assigned to corn ethanol, sugarcane ethanol, and electricity are not based on best available economic and scientific information, reliable data and methodologies, and need to be corrected before CARB tries to move forward with the Proposed Amendments. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, see staff responses to comments B4-25a through B4-25i above.

B4-26 The commenter urges CARB to reconsider the amendments on the treatment of renewable electricity for fuel pathways. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. The proposed book-and-claim accounting for renewable or low-CI electricity supplied as a transportation fuel or for hydrogen production are modelled off the existing provisions for renewable natural gas used in the natural gas vehicles. Further, for electric vehicles and hydrogen stations, opportunities for co-location of low-CI electric generation assets may be limited due to small land-area footprints. The book-and-claim accounting is not allowed for renewable or low-CI electricity used as process energy as similar flexibility is not allowed for renewable natural gas used as process energy.

B4-29 The commenter introduces the WSPA alternative. See response to comment B4-50 regarding the WSPA alternative.

B4-30 The commenter introduces the E15 alternative. See response to comment B4-51 regarding the E15 alternative.

B4-33 The commenter states that LCFS regulation and Proposed Amendments do not comply with AB 32 for the reasons identified below. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Staff disagrees with the commenter's argument that the LCFS Regulation and Proposed Amendments do not comply with AB 32, as explained in more detail below.

The commenter states that the LCFS regulation has resulted in increased and unmitigated NOx emissions from biodiesel since its inception and poses questions regarding the design and implementation of the VNRM. These issues are specifically and directly addressed in Section A (Executive Summary), Section C.3.a (Estimation of LCFS Attributed Biomass-Based Diesel Volumes) and Section D.4.a (Description of Remedial Measure to Offset Historical LCFS-attributed Biomass-based Diesel NOx Emissions of the Final NOx Disclosure Discussion). Please also see response to comment B4-3 regarding the design and implementation of the VNRM.

The commenter states that substantial evidence suggests that NOx emissions associated with biodiesel will increase in the future. The commenter further states that the proposed mitigation for biodiesel NOx emissions are based on assumptions regarding the use of renewable diesel, alternative jet fuel and development of solar steam projects, none of which are required to occur, and all of which are speculative. Staff's analysis in the Final EA (see Section 4.B.3 and "LCFS Amendments Air Quality Calculations (August 15, 2018)" Excel Spreadsheet) indicates that NOx emissions due to biodiesel use will decrease in the future due to in-use requirements in the ADF Regulation. As indicated above, staff's analysis was conservative, and likely overestimated LCFS-attributed NOx emissions due to biodiesel use. Also, see comment B7-1 and response to comment B4-36 related to the conservative nature of staff's analysis of LCFS NOx emissions due to biomass-based diesel use.

Biodiesel, renewable diesel, alternative jet fuel, and solar steam projects are incentivized by the LCFS, thus it is appropriate to look at the emissions of these and other compliance options under the LCFS together as a whole. Please also see response to comment B4-40 related to renewable diesel use and biodiesel use as compliance options.

Staff's projections of future biodiesel use, renewable diesel use, alternative jet fuel use, and development of solar steam projects are estimates that contain inherent uncertainty. However, staff believe that these projections represent reasonably foreseeable and conservative estimates based on analysis of historical data and knowledge of current and anticipated future conditions and policies.

The commenter states that the LCFS regulation will result in construction of new or modified facilities for alternative fuels incentivized by the regulation that will lead to increased criteria pollutant emissions that CARB states are "significant and unavoidable." Staff's analysis in the Final EA (see Section 4.B.3) concluded that construction of new or modified facilities could lead to increased short-term criteria pollutant emissions increases. While impacts should be reduced to a less-than-significant level by land use and/or permitting agency conditions of approval, the Final EA takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that short-term construction-related air quality impacts resulting from the development of new facilities or modification of existing facilities associated with the Proposed Amendments would be potentially significant and unavoidable.

Regarding commenter's fuel shuffling concern, see response to comment B4-22.

The commenter makes three misleading claims meant to imply that the LCFS contravenes AB 32. First, the commenter asserts the Legislature "wanted to ensure that criteria pollutants – such as NOx – would not increase," citing Health and Safety Code section 38501. Second, the commenter points out that CARB should design market-based compliance mechanisms to prevent increases in "criteria pollutants," citing Health & Safety Code section 38570, subd. (b)(2). Finally, the commenter makes the irrelevant assertion that certain GHG emission reduction measures – not the LCFS – must not interfere with efforts to maintain ambient air quality standards, and must "minimize leakage," citing Health & Safety Code section 38562, subds. (b)(4) and (8)

Taking those points in order, we first note that the Legislature did not say "NOx may not increase" from any particular GHG reduction measure, although the Legislature knows how to direct CARB to reduce NOx specifically.[15] Instead, the legislature expressed its intent that greenhouse gas control efforts "complement[] the state's efforts to improve air quality." Health & Safety Code § 38501(h) (*see also* Health & Safety Code, § 38562(b)(4) (using similar language)). The direction is to ensure that greenhouse gas control programs are consistent with criteria air pollutant control efforts – efforts that generally focus on compliance on an air-basin wide level based on a flexible mixture of various control programs and incentives. These efforts, expressed in the state's implementation plans for ambient air quality, as a rule, do not ordinarily contain strict prohibitions on increases from any one source, much less any one program, provided that a

[15] *See, e.g.,* Health & Saf. Code, § 43018, subd. (b) [CARB must act to achieve "a reduction in emissions of oxides of nitrogen of at least 15% from motor vehicles"].

pathway to attainment is maintained across these programs. It would be an error to impose a stricter rule on greenhouse gas programs than statute requires for criteria air pollutant programs themselves. In any event, the original LCFS reduced NOx[16] as do the Proposed Amendments.[17] Even more so, the Legislature was not trying to say "NOx may not increase in any single set of circumstances, even if NOx is decreased overall." We also emphasize that NOx is not the only criteria pollutant, and the LCFS's net operation is to significantly improve health outcomes and serve compliance with ambient air quality goals. CARB has taken a series of steps, in any event, to ensure that any NOx emissions that may conservatively be attributed to the LCFS are remediated or mitigated. It is worth noting that California's most successful criteria pollutant reduction measures historically – vehicle emission standards and vehicle fuel specifications – have required countless complex technological and chemical tradeoffs where the means for reducing one pollutant can cause an increase in a different pollutant. The LCFS design is unusually successful in that it is intended in part to reduce greenhouse gas emissions, but also incents fuels that reduce many criteria pollutants.

As to the second point, the cited requirement in Health & Safety Code section 38570, subd. (b)(2) is inapplicable to the LCFS, which specifically applies to California's Cap-and-Trade regulation. But both the original LCFS and the Proposed Amendments would more than satisfy such a requirement if applicable, because both were designed to reduce criteria pollutants. Only by looking at a single pollutant (NOx), and further limiting the examination to one subcategory (low cetane) within a single type of fuel (biodiesel) used in one category of engine (heavy-duty, pre-2010 diesel engines) is there evidence of a pollutant increase, while the operation of the program as a whole (not to mention CARB's larger set of programs) continues to support air quality attainment requirements. And nowhere does the commenter suggest that the LCFS was "designed" to accomplish that anomalous result.

As to the commenter's third point, the LCFS was published on a list of discrete early action measures, and was adopted before 2010, meaning that the LCFS is an "early action" measure adopted pursuant to Health & Safety Code section 38560.5. Nothing in AB 32 or elsewhere in law suggests that CARB may never amend or repeal and adopt a new LCFS after 2010.

Read as a whole, the Global Warming Solutions Act contains multiple strategies. For example, the act calls for early action measures to be

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[16] *See,* Initial Statement of Reasons (2009), p. VII-21, Table VII-13 available at https://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf .

[17] *See,* Initial Statement of Reasons (2018), p. V-2, Figure V-1 available at https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf .

published in 2007 and adopted and enforceable by January 1, 2010.[18] In separate provisions, the act calls for a scoping plan to guide measures to achieve the 2020 emission limit[19] followed by adoption of measures to achieve that limit, enforceable by January 1, 2012[20].

The commenter – ignoring the structure and text of the act – notes that the LCFS, an "early action" measure, does not meet the requirements applicable to the later "scoping plan" measures.

The commenter returns its focus to the narrow, anomalous NOx increase, suggesting that CARB's mitigation plan relies on expenditures of NOx-reduction funds, but that nothing "requires this [mitigation] to occur." Regardless whether that is true (it is not), we note that nothing in the LCFS or the Proposed Amendments "requires" anyone with a pre-2010, heavy-duty diesel engine to use low-cetane biodiesel. Both the potential NOx emissions commenter purports to be concerned about and the mitigation are in the future, and have been anticipated based on CARB's best expert evaluation of the available information and its long experience implementing and overseeing air quality programs throughout California. Moreover, as described in more detail in response to B4-3, CARB has followed through to encumber grants for $9 million that require NOx reduction projects to be implemented in exchange for funding.

B4-35 The commenter provides an overview of CEQA requirements and CARB's certified regulatory program in their view. As noted in the comment, CARB must prepare an environmental document that includes alternatives to the project and mitigation measures to avoid or reduce any significant or potentially significant environmental effects that may occur as a result of project implementation. Comments on the environmental analysis must also be summarized and responded to before final action is taken on the project. CARB prepared the Draft EA as the functional equivalent document, which contains the required environmental analysis. As required by the certified regulatory program, the Draft EA provides a programmatic and comprehensive analysis of the environment effects that could occur from implementation of the Proposed Amendments. This document contains a summary and response for each substantive environmental comment submitted on the Draft EA, as well as responses to many comments that are not substantive environmental comments in the interest of comprehensive disclosure.

B4-36 The commenter states concerns that the ISOR underestimates NOx emissions based on the analysis of RFS incentives, and recounts some of the

[18] Health & Saf. Code §38560.5.
[19] Health & Saf. Code §39561.
[20] Health & Saf. Code §36562, subd. (a).

legal history in related litigation. Those legal documents speak for themselves as to their content. Staff disagrees with the commenter's statement that the ISOR underestimates LCFS-attributed NOx emissions due to biodiesel use as a result of the ISOR's analysis related to incentives under the federal RFS; in fact, the analysis produced by staff is conservative and likely overestimates NOx impacts. As detailed in Section C and Appendix 1 of Appendix G of the ISOR, CARB evaluated multiple methods for attributing consumption of biomass-based diesel volumes to the LCFS, selecting the method that results in the most conservative (highest) cumulative historical NOx emissions increase attributed to the LCFS. Please also see response to comment B7-1 regarding the conservative nature of CARB's analysis of LCFS NOx emissions due to biomass-based diesel.

The commenter states that the proposed remediation measure does not ensure that remediation will occur, and that the forward-looking mitigation is not in line with CEQA since new technology diesel engines (NTDEs) and renewable diesel volumes are not required. Staff disagrees with the commenter's statement that the mitigation measures proposed by CARB for past NOx emissions do not contain all of the components required under CEQA. Please see response to comment B4-3 related to the design and implementation of the VNRM.

Staff also disagrees with the commenter's assertion that forward-looking mitigation does not meet CEQA's standards. The amendment to the ADF regulation proposed by staff (see Section 2.F of the Final EA) is enforceable mitigation that meets CEQA's standards. As noted in the 2015 ADF staff report, both renewable diesel and NTDEs are offsetting factors. The production and use of renewable diesel is incentivized by the LCFS regulation, and therefore, is a compliance response, and not a mitigation measure to reduce NOx emissions from biodiesel. Similarly, the adoption of NTDEs is also not a mitigation measure but a factor that must be projected in order to analyze project impacts in future years. In evaluating the impacts associated with the proposed amendment to the ADF regulation, staff made reasonable assumptions about the offsetting factors (e.g., rates of adoption of NTDEs and renewable diesel use) to evaluate future impacts, consistent with the CEQA Guidelines (14 CCR 15000 et eq.) and CARB's certified regulatory program under CEQA (14 CCR 15251(d); 17 CCR 60000-60008). More information about the possible pathway to LCFS compliance is available in Chapter VIII and Appendix E of the ISOR.

B4-37 The commenter characterizes various aspects of the court's proceedings in cases related to this rulemaking and raises questions about steps CARB has taken in response. The commenter contends that CARB could have done more to reduce biodiesel use or mitigate NOx in 2009 and instead incentivized biodiesel though a favorable CI value. Thus, the attribution of most NOx emissions from biodiesel to the RFS is not supportable, in commenter's view, and even if the LCFS was not solely responsible, CARB should still discuss the cumulative effect. This suggests that no matter the attribution, CARB should address, analyze, and mitigate all cumulative impacts under CEQA.

Commenter's characterization of what CARB could or could not have done in the past is largely irrelevant, as the question for impacts analysis is how CARB manages NOx emissions going forward – though CARB has gone above this requirement by addressing NOx from all biodiesel use, not just attributable to the LCFS, and has voluntarily remediated past NOx that could be attributed to actions in CARB's control on a conservative basis. Thus, though there is no requirement that CARB must mitigate the emissions of every drop of biodiesel sold in the state, CARB has entirely addressed the impacts of biodiesel emissions going forward and has remediated past potential impacts of the LCFS even if these impacts were not, in fact, caused by CARB's actions.

CARB adopted the ADF regulation to ensure that biodiesel use in California is mitigated in accordance with the requirements of CEQA, as well as CARB's policy goals, regardless of which policy incentivized that biodiesel use. Consistent with the Superior Court's direction, CARB staff analyzed NOx emissions and potential impacts that could be attributed to implementation of the LCFS regulations, and based on those results developed the VRNM to remediate those potential NOx emissions increases. As detailed in Section C and Appendix 1 of Appendix G of the ISOR, CARB evaluated multiple methods for attributing consumption of biomass-based diesel volumes to the LCFS, selecting the method that results in the most conservative (highest) cumulative historical NOx emissions increase attributed to the LCFS.

Neither the EA (Appendix D of the ISOR) nor Appendix G of the ISOR avoids mitigation of potential future NOx emissions due to biodiesel NOx emissions. The proposed mitigation measure, an amendment to the ADF Regulation to indicate that the sunset of in-use requirements is based on penetration of NTDEs for both on-road vehicles and off-road vehicles and equipment, addresses potential NOx emissions due to all mobile source biodiesel NOx emissions in California (i.e., those attributed to the LCFS and those not attributed to the LCFS). Both the EA and Appendix G included cumulative analyses (see Section 5 of the EA and Section D.3.a.viii of Appendix G), as required by CEQA.

The commenter states that CARB has already taken credit for NOx reductions due to LCFS-attributed volumes of renewable diesel as part of the "Low-Emission Diesel" (LED) requirement of the agency's Mobile Source State Implementation Plan (SIP) Strategy. The commenter is incorrect that CARB has already formally committed to taking credit in CARB's Mobile Source SIP Strategy for NOx emissions reductions from the quantities of renewable diesel use attributed to the LCFS. The LED measure presented in in the 2016 State Strategy for the SIP published in May 2017[21] is a measure concept and includes estimated emissions reduction from the measure. The details of exactly how that program would work, and what emissions reductions it would achieve, will be detailed in a future rulemaking process.

B4-38 The commenter contends that CARB's proposed remedial measure is not sufficient because it defers formulation of the measure to a point in the future, provides no explanation of how the program would get a ton for ton reduction, or where those reductions would occur, or how it would be funded. The commenter suggests there is no guarantee that CARB would provide a specific amount of funding.

As discussed in Section D.4.a of the Final NOx Disclosure Discussion, the ADF, and proposed amendments to the ADF, would fully mitigate any future potential NOx emissions related to increased biodiesel use in California. Nonetheless, CARB concluded that additional future NOx reduction efforts are appropriate, and would further improve air quality in the future. Therefore, CARB has taken action to reduce future NOx emissions in an amount equal to total estimated historical potential LCFS-attributed biomass-based diesel NOx emissions, determined on the year-by-year level and excluding years in which NOx reductions were estimated, through a voluntary NOx remediation measure. Due to the short atmospheric lifetime of NOx emissions, it is not physically possible, and is therefore infeasible, to physically remove any specific potentially significant historical LCFS NOx emissions from the atmosphere. Accordingly, the Final NOx Disclosure Discussion proposes remediation, not mitigation, for potential NOx emissions increases that may have already occurred due to historical biomass-based diesel use. This remediation approach is consistent with the CEQA guidelines, which do not provide specific guidance regarding remediation of historical emissions. This approach is designed to create future environmental benefits in California as CARB works to reduce GHG and other pollutants with the LCFS and other air quality and climate policies.

Staff disagrees with the commenter's statements regarding the adequacy of CARB's remediation measure. Staff also disagrees that there is no evidence that CARB is committed to provide funding under the VNRM. CARB has encumbered $9 million in funding for district projects to reduce NOx. The projects must reduce NOx in line with the cost effectiveness levels outlined in Attachment A of Resolution 18-22, which is consistent with full remediation. The reductions for those projects will be tracked by CARB staff. Staff also disagrees with the commenter's statements regarding the lack of information regarding the types of projects to be funded, how the program will result in

[21] Revised Proposed 2016 State Strategy for the State Implementation Plan. CARB. March 7, 2017. Available at: https://www.arb.ca.gov/planning/sip/2016sip/rev2016statesip.pdf

ton-for-ton remediation of past NOx emissions, which districts would be the focus of funding efforts and whether these districts would be located in areas most affected by historical NOx emissions increases, and how remediation would be funded. Please see response to comment B4-3 and Section D.4.a of the Final NOx Disclosure Discussion regarding the design and implementation of the VNRM, and CARB's funding commitment to the VNRM.

The commenter refers to a previous comment (B4-36) indicating that historic NOx emissions attributed to the LCFS are underestimated. Please see comment B7-1 and response to comments B4-33 and B4-36 regarding the conservative nature of CARB's analysis of LCFS NOx emissions due to biomass-based diesel.

B4-39 The commenter states that the consensus within the scientific literature is that NTDEs using biodiesel blends of B20 or less cause NOx emissions to increase. The commenter also asserts that CARB staff and CARB contractors have published several studies indicating that biodiesel increases NOx emissions from NTDEs.

As stated by the commenter, and previously detailed in the response to comment ADF 17-4 of the Environmental Analysis for the 2015 LCFS re-adoption,[22] staff reviewed the available literature on emissions from engines meeting the latest emission standards (NTDEs) through the use of Selective Catalytic Reduction (SCR) using biodiesel during the rulemaking process for the ADF regulation and the amendments to the LCFS regulation in 2015. Two studies were reviewed and used in staff's analysis: 1) a study conducted by the National Renewable Energy Laboratory ("Lammert study") that found NOx emissions control eliminates fuel effects on NOx, up to and including B100, and 2) a study at UC Riverside which tested B50 blends and found a NOx increase (blends below B50 were not tested). Three other studies on NTDEs were reviewed by staff and rejected as not relevant because these three studies were performed using retrofit devices rather than entire systems designed for commercial use. Based on these results, staff reasonably concluded that the use of lower levels of biodiesel with NTDEs results in no increase in NOx. However, there is some uncertainty in the NOx impacts at higher biodiesel blends. Therefore, staff took a conservative approach in designing the proposed ADF Regulation by limiting the conclusion of no increase in NOx from NTDEs to the use of blends B20 and below.

The studies that the commenter refers to on SCR inefficiencies did not examine biodiesel; therefore, CARB believes it is not feasible to make

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[22] Responses to Comments on the Draft Environmental Analysis for the Low Carbon Fuel Standard and Alternative Diesel Fuel Regulations. CARB. September, 2015. Available at: https://www.arb.ca.gov/regact/2015/lcfs2015/earesponsetocomments.pdf

conclusions related to NOx emissions from those studies. However, CARB has evaluated the scenario the commenter outlined in Appendix A and found net NOx decreases for all future years analyzed.

CARB acknowledges SCR effectiveness issues impact NOx emissions for conventional diesel (i.e., EMFAC 2017 has addressed SCR effectiveness during low loads as well as tampering and maintenance issues). However, the potential for biodiesel use to increase NOx emissions beyond the increase from conventional diesel use in those conditions is a complex technical issue that deserves additional study, and has not been fully addressed by the literature. There are technical reasons to believe that the use of biodiesel would not lead to an additional increase in NOx above conventional diesel under those conditions. For example, the use of thermal management strategies by engine manufacturers maintains engine exhaust temperatures above a threshold level to allow for optimal NOx reduction.[23] Staff has communicated with engineers from engine manufacturers, who have supported this position. CARB is undertaking an engine testing study that aims to better quantify the NOx emissions impact of biodiesel and renewable diesel use in NTDEs in situations where the SCR may not be operating at maximal efficiency. To be clear, CARB is undertaking that study to shed light on a complex technical issue that has not yet been sufficiently studied, not because it anticipates adverse impacts will be revealed.

The commenter asserts that NOx increases due to biodiesel use in NTDEs could result in up to 9.72 additional tons per day of NOx emissions statewide in 2020. Staff considered the scenario presented by the commenter in Appendix A, Attachment 4 of the commenter’s letter dated April 26, 2018 (i.e., that the SCR system in NTDEs is ineffective 70 percent of the time)[24] in the NOx emissions analyses for the Final NOx Disclosure Discussion and the Final EA, and found that it did not change the conclusion that the Proposed Amendments result in NOx reductions on a statewide basis. The commenter’s scenario leads, effectively, to lower emission controls on NTDEs such that both biodiesel NOx increases and renewable diesel NOx decreases are magnified. In total, the NOx decreases from renewable diesel overwhelm the NOx increases from biodiesel, resulting in net NOx decreases for all future years analyzed.

B4-40 The commenter states that the use of renewable diesel as a mitigation measure for biodiesel NOx emissions is not an enforceable mitigation

[23] Misra, Chandan, et al. In-Use NOx Emissions from Model Year 2010 and 2011 Heavy-Duty Diesel Engines Equipped with Aftertreatment Devices. Environ. Sci. Technol. 2013, 47, 7892-7898.

[24] Based on a study that evaluated NOx emissions for 90 different SCR-equipped heavy-duty vehicles representing 19 different vocations, staff believe the commenter’s estimate of SCR ineffectiveness is unrealistically high. Boriboomsomsin, Kanok et al. 2017. Collection of Activity Data from On-Road Heavy-Duty Diesel Vehicles. May.

measure under CEQA, and that the conclusions that expected levels of renewable diesel usage are sufficient to offset NOx emissions from biodiesel is unsupported by evidence.

The production and use of renewable diesel is incentivized by the LCFS regulation, and therefore, is a compliance response, and not a mitigation measure to reduce NOx emissions from biodiesel. Similarly, the production and consumption of biodiesel is a compliance response. There is nothing in the LCFS regulation requiring industry to use either biodiesel or renewable diesel at any particular level. Please see responses to comments B4-33, B4-36, and B4-40 regarding the use of biodiesel and renewable diesel as compliance options. In analyzing the impacts of the Proposed Amendments, staff considered reasonably foreseeable volumes of renewable diesel and biodiesel, among other fuels, based on potential methods of compliance with the LCFS and determined impacts based on those conditions.

The commenter states that CARB has already formally committed to taking credit for LCFS NOx reductions as part of a "Low-Emission Diesel" requirement as part of the CARB's Mobile Source SIP. Please see response to comment B4-37 related to the Low-Emission Diesel measure.

B4-41 The commenter asserts that solar steam projects cannot be considered an effective mitigation measure under CEQA because they are not based on an enforceable obligation, and there is no assurance such projects will actually be implemented. The analyses conducted by staff and summarized in both Attachment H to the Second Notice of Public Availability of Modified Text and the EA document estimated the statewide NOx and PM emission impacts from the Proposed Amendments as a whole. Staff did not claim that NOx reduction associated with solar steam projects can mitigate any potential emission increase from biodiesel.

B4-42 The commenter asserts that any offset for AJF use is not based upon an enforceable obligation, and there is no assurance AJF will displace conventional jet fuels at any particular quantity or rate. As explained in the draft EA, staff analysis of potential environmental impacts is based on estimated reasonably foreseeable compliance actions. Because the LCFS is a market-based mechanism for spurring investment in the development of low carbon transportation fuels, while staff may estimate future reasonably foreseeable compliance actions, the actual mix of future compliance responses is unknowable.

B4-43 The commenter correctly states that the post-mitigation discussions in certain resource areas throughout the Draft EA find that potentially significant impacts would remain significant and unavoidable, although mitigation is available to reduce impacts to a less-than-significant level. CARB notes that, as explained in Chapter 4 of the Draft EA, it does not have the lead agency authority to implement mitigation measures contained in the Draft EA, but discloses mitigation measures which, if implemented by the lead agency undergoing environmental reviews of future projects constructed and operated as a result of the Proposed Amendments could reduce the severity of significant environmental effects.

B4-44 The commenter states that an environmental document cannot conclude that an impact would be significant and unavoidable without first providing a discussion and analysis. Chapter 4 of the Draft EA contains a programmatic and comprehensive analysis of the potential environmental effects of the reasonably foreseeable compliance responses related to the Proposed Amendments, in all resource areas. The Draft EA takes a conservative approach and considers some environmental impacts as potentially significant because of the inherent uncertainties regarding the relationship between physical actions that are reasonably foreseeable under the Proposed Amendments and environmentally sensitive resources or conditions that may be affected.

While the Draft EA fully analyzes all reasonably foreseeable impacts, it contains a degree of uncertainty regarding implementation of mitigation for potentially significant impacts. The programmatic analysis in the Draft EA does not allow for a precise description of the details of project-specific mitigation because CARB cannot predict the location, size, design, or setting of specific compliance responses that may result from implementation of the Proposed Amendments, and does not have lead agency authority to implement project-specific mitigation to reduce significant impacts. Future projects constructed and operated following the adoption of the Proposed Amendments would undergo project-level environmental review and, if impacts were found to significant, appropriate mitigation measures would be applied and enforced by the lead agency. CARB discloses a menu of potential mitigation measures that could be applied at the project-level; however, for the reasons stated above, acknowledges that application of such measures would be the responsibility of the lead agency conducting environmental review under CEQA.

As a result, there is inherent uncertainty in the degree of mitigation that would ultimately need to be implemented to reduce any potentially significant impacts identified in the Draft EA. Consequently, the Draft EA takes the conservative approach in its post-mitigation significance conclusions (i.e., concluding that feasible mitigation may not be sufficient) and discloses, for CEQA compliance purposes, that potentially significant environmental impacts may be unavoidable, where appropriate. It is also possible that during project-level environmental review, the amount of mitigation necessary to reduce environmental impacts to below a significant level may be far less than disclosed in the Draft EA. It is expected that many individual development projects would be able to feasibly avoid or mitigate impacts to a less-than-significant level through implementation of project-level mitigation measures. If a potentially significant environmental effect cannot be feasibly mitigated with certainty, the Draft EA identifies it as potentially significant and unavoidable (see discussion on page 46 of the Draft EA, under subheading Significant Adverse Environmental Impacts and Mitigation Measures).

Thus, the analysis contained in Chapter 4 of the Draft EA provides an appropriate level of review.

B4-45 The commenter states the EA does not include the same kind of health risk assessment of potential California biofuel facilities that was presented in the 2015 LCFS ISOR as part of its analysis of air quality impacts in the 2018 EA. In the Air Quality Chapter (Chapter V) of the 2018 ISOR, staff included a section called "Localized Health Risk Assessment for a Potential California Biofuel Facility." This section refers to and summarizes the health risk assessment study in the 2015 LCFS staff report that evaluated the localized health impacts associated with toxic air contaminants that could be emitted from a typical biofuel facility within California. Staff determined this study was adequate and did not need to be revised, and no commenter has asserted otherwise.

B4-46 The commenter asserts that the EA's estimate of potential impacts associated with the construction of new or modified facilities are understated. The estimated emissions calculated in the 2015 LCFS staff report were based on permits and engineering evaluations for a cellulosic ethanol facility in Kansas. Staff no longer believed that this would be representative of a potential cellulosic ethanol facility in California because of California's stricter air quality laws.

For this rulemaking, staff updated the estimated emissions of a potential cellulosic ethanol facility in California. As stated in Appendix F, staff obtained average estimated criteria pollutants emissions of seven pre-commercial or "demonstration" cellulosic ethanol refineries in the U.S. and similar permit data for four commercial U.S. corn ethanol facilities that were selected randomly from available permit documentation, and calculated emission ratios between cellulosic ethanol facilities and corn ethanol facilities. Staff then multiplied this ratio by the emission factors for California corn ethanol facilities to estimate the emission factors for cellulosic ethanol facilities in California.

B4-47 The commenter states that the Draft EA refers to specific mitigation measures to reduce effects from new or modified facilities but does not include any actual mitigation measures. The commenter identifies Mitigation Measure B.3.b as an example, stating that it does not include any language suggesting what the text of that mitigation measure might be, and argues that under the measure, no mitigation is necessary. The Draft EA provides a programmatic level of review. As discussed under Section 1.E.2, Scope of Analysis and Assumption, "[t]he degree of specificity required in a CEQA document corresponds to the degree of specificity inherent in the underlying activity it evaluates. Environmental analysis for broad programs cannot be as detailed as for specific projects" (CEQA Guidelines 15146) (see paragraph three, page eight of the Draft EA). That is, because the Proposed Amendments analyzed in the Draft EA addresses a broad market-based regulatory program, a general level of detail is appropriate. In addition, the Draft EA contains a degree of uncertainty regarding implementation of mitigation for potentially significant impacts. The programmatic analysis in the Draft EA does not allow for a precise description of project-specific mitigation because CARB cannot predict the location, size, design, or setting of specific compliance responses that may result, and does not have lead agency authority over implementation of specific infrastructure projects that may occur as a result of implementation of the Proposed Amendments. Mitigation measures included in the Draft EA provide list of recognized practices routinely required to avoid and/or minimize the severity impacts.

The commenter states the Mitigation Measure B.3.b does not include language suggesting what the text of the mitigation measure might be. To the contrary, Mitigation Measure B.3.b contains a list of recognized practices routinely required to avoid and/or minimize impacts to air quality. This list is reproduced as follows (see page 58 of the Draft EA):

- Proponents of new or modified facilities constructed as a result of reasonably foreseeable compliance responses would coordinate with local or State land use agencies to seek entitlements for development including the completion of all necessary environmental review requirements (e.g., CEQA). The local jurisdiction with land use authority would determine that the environmental review process complied with CEQA and other applicable regulations, prior to project approval.
- Based on the results of the environmental review, proponents would implement all feasible mitigation identified in the environmental document to reduce or substantially lessen the construction-related air quality impacts of the project.
- Project proponents would apply for, secure, and comply with all appropriate air quality permits for project construction from the local agencies with air quality jurisdiction and from other applicable agencies, if appropriate, prior to construction mobilization.
- Project proponents would comply with the federal Clean Air Act and the California Clean Air Act (e.g., New Source Review and Best Available Control Technology criteria, if applicable).
- Project proponents would comply with local plans, policies, ordinances, rules, and regulations regarding air quality-related emissions and associated exposure (e.g., construction-related fugitive PM dust regulations, indirect source review, and payment into offsite mitigation funds).

- For projects located in PM nonattainment areas, prepare and comply with a dust abatement plan that addresses emissions of fugitive dust during construction and operation of the project.

As discussed on pages 70 and 71 of the Draft EA, “while CARB does not believe significant localized increases are likely and anticipates overall beneficial long-term operational impacts and if they were to exist impacts should be reduced to a less-than-significant level by land use and/or permitting agency conditions of approval…” Thus, the Draft EA does identify feasible mitigation measures that could reduce potentially significant impacts on air quality if implemented by the lead agency overseeing project-specific environmental review. This is provided in an abundance of caution and for the purposes of complete public disclosure; however, CARB does not anticipate significant localized criteria air pollutant emissions and expects overall beneficial long-term operational impacts statewide (see second to last paragraph on page 69 of the Draft EA).

The commenter expresses confusion related to if Mitigation Measure B.3.b would reduce the impacts of the Proposed Amendments, and the LCFS regulation as a whole, or if no mitigation is necessary. As stated in the first paragraph on page seven, “[p]roject-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority.” That is, the mitigation measures identified in Chapter 4 of the Draft EA would, when implemented at the project level, likely reduce impacts resulting from the operation of new or modified facilities, which is considered to be a reasonably foreseeable compliance response associated with the Proposed Amendments (see Chapter 2 of the Draft EA for the project description and a list of reasonably foreseeable compliance responses).

The comment notes that Appendix G of the Staff Report references specific mitigation/remedial measures designed to lessen the potentially significant environmental impacts associated with NO_X emissions from biodiesel. This issue is addressed beginning with the last paragraph on page 64 and the first paragraph on page 65 of the Draft EA, as provided herein:

> Adoption of the Proposed Amendments would be expected to increase the use of biodiesel and renewable diesel in lieu of conventional diesel, while mitigating tailpipe NO_X emissions increases associated with biodiesel use for all years, including beyond 2022. In estimating the impacts of the Proposed Amendments on long-term operational NO_X emissions related to biomass-based diesel use, staff used the same methodology for fuel volume and emissions attribution to the LCFS as that developed and used in Appendix G of the ISOR. Staff included an “LCFS-attributed” value to satisfy the instructions in the previously-mentioned October 18, 2017 writ of mandate to determine the biodiesel and renewable diesel volumes and impacts that are attributable to the implementation of the LCFS regulation.

> LCFS-attributed values were then compared to baseline values, which in this case are properly set in 2016, as explained in Chapter 1(D) [of the Draft EA].
>
> Overall, biomass-based diesel use attributed to the LCFS would result in a potential decrease in NO_X emissions relative to use of conventional diesel in all State- and federally-designated ozone non-attainment areas in 2019 through 2030. Biomass-based diesel use attributed to the LCFS would result in a PM emission decrease relative to use of conventional diesel in all years from 2019 through 2030. Overall, biodiesel and renewable diesel fuels have been found to reduce tailpipe PM emissions relative to conventional diesel. Renewable diesel has been found to decrease tailpipe NO_X relative to conventional diesel; however, biodiesel has been found to increase NO_X emissions in some cases, depending on feedstock and type of engine of used. The Alternative Diesel Fuel regulation was approved in 2015 requiring NO_X mitigation additive use to address potential increased NO_X emissions from biodiesel use. Pursuant to the ADF, multiple NO_X mitigation methods have been certified by CARB to mitigate any additional NO_X emissions from biodiesel use compared with the reference diesel. Renewable diesel use also reduces NO_X emissions compared to use of conventional diesel, and since both renewable diesel and biodiesel use displaces conventional diesel use, renewable diesel helps offset increased NO_X emissions from biodiesel.

Thus, because the Proposed Amendments would not result in significant impacts related to NO_X emissions, no mitigation measures are required. Similarly, recognized practices that are routinely required to avoid and/or minimize impacts are identified for other resource areas addressed in the Draft EA (e.g., aesthetics, agricultural and forest resources, air quality, biological resources, cultural resources, energy demand, geology and soils, GHG emissions, hazardous and hazardous materials, hydrology and water quality, land use and planning, mineral resources, noise, population and housing, public services, recreation, transportation and traffic, and utilities and service systems). (See Attachment 2 of the Draft EA for a summary of environmental impacts and mitigation measures.) The programmatic analysis in the Draft EA does not allow for a precise description of project-specific mitigation because CARB cannot predict the location, size, design, or setting of specific compliance responses that may result from implementation of the Proposed Amendments. Further, as stated in Chapter 4 of the Draft EA, CARB does not have lead agency authority to implement project-specific mitigation for infrastructure projects that may occur under the Proposed Amendments. As a result, there is inherent uncertainty in the degree of mitigation that would ultimately need to be implemented to reduce any potentially significant impacts identified in the Draft EA. Thus, CARB cannot develop mitigation measures to lessen the severity of impacts beyond the level of detail provided in the Draft EA. The Draft EA properly addresses, analyzes, and identifies where potentially significant impacts could occur as a result of the Proposed Amendments.

Please see response to comment B4-64 for responses to comments on Appendix A, Attachment 5 of this comment letter, which includes recommended mitigation measures.

B4-48 The commenter repeats an unfounded premise that evidence suggests that the LCFS is causing fuel shuffling, and suggests that the draft EA should have considered potential environmental impacts that could result from fuel shuffling. Please see response to comment B4-22 for a discussion related to potential concerns with fuel shuffling and the LCFS.

Regarding commenter's suggestion that CARB must "minimize leakage," Health and Safety Code section 38562(b) does not apply to the LCFS, as more fully explained in response to B4-33.

B4-49 The commenter correctly characterizes some of the CEQA requirements related to the alternatives. No specific comments were included on the Draft EA that requires a response.

B4-50 The commenter correctly states that the Draft EA eliminates the WSPA Alternative for detailed consideration. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. The purpose of the alternatives analysis is to determine whether different approaches to or variations of the project would reduce or eliminate significant project impacts, within the basic framework of the objectives, a principle that is consistent with CARB's regulatory requirements. As discussed in the Draft EA, the WSPA Alternative, referred to in the Draft EA as the "No LCFS Alternative," is not responsive to the direction in the 2017 Climate Change Scoping Plan, which includes LCFS as one of the key measures for achieving the State's 2030 GHG reduction target as mandated in statute by Senate Bill (SB) 32. It is also unclear how the incentive portion of the No LCFS Alternative would be funded and which fuels would be targeted (see fourth paragraph of page 208 of the Draft EA). Thus, as discussed on page 208 of the Draft EA, most of the project objectives would not be achieved; therefore, the No LCFS Alternative was dismissed as infeasible and does not warrant further evaluation (CEQA Guidelines Section 15126.6[c]). As such, the Draft EA appropriately dismisses the WSPA Alternative (i.e., No LCFS Alterative) from detailed evaluation. No changes to the document are necessary.

See response to comment B4-52 for a discussion related to CEQA requirements for alternatives.

For additional discussion related to the WSPA Alternative, as staff noted in the ISOR (ISOR, pages IX-1 through IX-2 and Appendix D, page 207 to 208), WSPA's alternative would not be feasible because "CARB has not been appropriated funding" (ISOR, Appendix IX, page IX-2) to create WSPA's suggested incentives. Furthermore, "WSPA's proposal did not provide clarity about how the incentive portion of their proposal would be funded or which fuels should be targeted by the new incentive program. Therefore, WSPA's proposal contains no guarantees that the following project objectives would be achieved:

- Reduce the CI of transportation fuels in the California market to a level comparable to staff's proposal (and in line with the Scoping Plan's method of reaching SB 32 targets by 2030);
- Provide greater diversification of the State's fuel portfolio;
- Provide reduced dependence on petroleum;
- Decrease the associated economic impacts of gasoline and diesel price spikes caused by volatile oil price changes;
- Provide greater innovation and development of cleaner fuels" (ISOR's Appendix D, pg. 208).

Furthermore, WSPA's proposal would create unnecessary policy uncertainty that will limit progress in the development of low carbon fuel producers and hinder the State's efforts to meet the State's 2030 and 2050 climate goals.

Additionally, the LCFS and Cap-and-Trade program requirements are reinforcing rather than duplicative for a variety of reasons; in the absence of the LCFS, Cap-and-Trade price would likely need to be higher, all else equal, to hit the State's SB 32 goals. Further, complementary policies, such as the LCFS, play a critical role in achieving important co-benefits. Specifically, the LCFS is helping to improve the state's air quality and supports rapid diversification in fuel types.

Moreover, the commenter cites an inaccurate section of the Health and Safety Code as party of the authority that establishes the LCFS; Health and Safety Code, § 38566, is not an authority the CARB cites for the establishment of the LCFS.

B4-51 The commenter recommends consideration of the E15 Alternative. This alternative is legally infeasible because the restrictions on higher ethanol blends and any amendments to current fuel regulations are beyond the scope of this regulatory proposal. An E15 alternative under which CARB would concurrently adopt fuel specifications for E15 and incorporate E15 into the LCFS is not a reasonable alternative because the LCFS is a performance standard that does not mandate the use of a specific transportation fuel. The adoption or amendment of a specific fuel specification regulation would require a new, separate rulemaking proceeding. Staff acknowledges the commenter's suggestion to consider ethanol blends beyond E10. Outside of this rulemaking, CARB is currently evaluating emissions data on higher ethanol blends to help determine whether the development of alternative fuel specifications for E15 would be appropriate.

Please see response to comment B4-50 for a discussion of the requirements related to alternatives.

B4-52 The comment states that the Draft EA does not contain a reasonable range of alternatives. Section 15126.6 (c) of the CEQA Guidelines addresses the selection of a range of reasonable alternatives:

> The range of potential alternatives to the proposed project shall include those that could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more of the significant effects. The EIR should briefly describe the rationale for selecting the alternatives to be discussed. The EIR should also identify any alternatives that were considered by the lead agency but were rejected as infeasible during the scoping process and briefly explain the reasons underlying the lead agency's determination. Additional information explaining the choice of alternatives may be included in the administrative record. Among the factors that may be used to eliminate alternatives from detailed consideration in an ERI are: i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts.

These guidelines were followed and complied with in Chapter 7 of the Draft EA, which addresses five alternatives, consisting of the No-Project Alternative and four action alternatives: 25 Percent Carbon Intensity (CI) Reduction Target Alternative, Exempt Biodiesel from the LCFS Alternative, No LCFS Incorporation of CCS Protocol Alternative, and Omit Alternative Jet Fuels from Generating Credits under the Low Carbon Fuel Standard Alternative. This represent a reasonable range of alternatives that provides information to decision-makers helpful information in considering approval of the Proposed Amendments.

The comment also states that the Draft EA should consider an alternative that does not include continuation of LCFS. CARB's certified regulatory program does not mandate consideration of a "No-Project Alternative." (Cal. Code Regs., tit. 17, Section 60006.) CARB is including Alternative-1, the No Project Alternative, to provide a good faith effort to disclose environmental information that is important for considering the Proposed Amendments. Under CARB's certified regulatory program, the alternatives considered, among other things, must be "consistent with the state board's legislatively mandated responsibilities and duties." (Cal. Code Regs., tit. 17, Section 60006.) When a project revises an existing regulatory program, the No-Project Alternative is considered to be the continuation of the existing regulatory program (CEQA Guidelines 15126.6[e][3][A]). Under the No-Project Alternative, the Proposed Amendments would not be approved.

Thus, CARB considered a reasonable range of alternatives. No changes to the Draft EA are necessary.

B4-53 The commenter states that the project objectives are too narrow. CARB disagrees. LCFS, established pursuant to Executive Order S-01-07, calls for a reduction in the CI of transportation fuels sold for use in California as one of the measures to meet the reductions in statewide GHG emissions mandated by the California Global Warming Solutions Act of 2006 (AB 32 and SB 32), codified at Health and Safety Code section 38500 et seq.). The project objectives include the underlying goals of reducing the CI of transportation fuels and are not overly restrictive. The evaluation of multiple feasible alternatives in this Draft EA supports this conclusion. See response to comment B4-52 for a discussion related to the range of alternatives presented in the Draft EA.

B4-54 The commenter repeats that implementing an LCFS program that inaccurately states the CI for any particular fuel will send the wrong "signal" to the downstream regulated parties, resulting in the use of fuels that result in higher GHG emissions. See response to comment B4-21.

B4-54a The commenter repeats that the ILUC for corn starch ethanol should be reduced from 19.8 g/MJ to 10.3 g/MJ. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. See response to comment B4-24.

B4-54b The commenter repeats that distillers' grain (DDG) methane avoidance credit is included in the current version of the GREET model but not incorporated into CA-GREET3.0. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. See response to comment B4-23a.

B4-54c The commenter states that the CI for corn starch under CA-GREET3.0 contains a value for the electricity that is used in transportation and distribution (T&D) with an emission factor developed using U.S. average power, even though most such emissions are likely to be in California. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. The CA-GREET3.0 model calculates GHG emissions for the indirect use of electricity in T&D. To limit the additional complexity of assessing multiple regional emission factors for indirect electricity as fuel is transported from a production facility to California, staff elected to use a representative factor and applied the U.S. average emission factor for electricity. This selection is not expected to have a measurable impact on the pathway CI, given the small amount of indirect electricity used in T&D.

B4-54d The commenter states that the CI for sugarcane does not include GHG emissions associated with ash that is trucked out to sugarcane fields and distributed on the ground to add nutrients back to the soil. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Although returning sugarcane bagasse-ash (SCBA) to soil may provide phosphorus and potassium as nutrients, one study[25] highlights limitations to the volume and frequency of such applications to prevent overloading of phosphorus in soil. Also, consideration of credits to the sugarcane ethanol pathway require information to support wide-spread commercial use of SCBA as a soil amendment. In addition, although one study[26] has published results from controlled studies using SCBA, there are no reports from national organizations or peer-reviewed literature to support any quantifiable fertilizer offsets by the use of this material as a soil amendment. Staff has therefore not considered GHG impacts or benefits attributable to SCBA. When such data becomes available, staff will review and make necessary adjustments.

B4-54e The commenter states that the CI for sugarcane is understated because the nitrogen content of biomass and fertilizer for sugarcane are far higher than estimated by CARB. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant

[25] Arif, 2016. Development of value added products from sugarcane boiler ashes. https://epubs.scu.edu.au/cgi/viewcontent.cgi?article=1498&context=theses
[26] Khan, 2006. Integrated use of boiler ash as organic fertilizer and soil conditioner. http://rdo.psu.ac.th/sjstweb/journal/30-3/0125-3395-30-3-281-289.pdf

environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. With regards to the nitrogen content of sugarcane biomass, staff has recommended that this value be corrected as a 2nd 15-day change (see staff response to comment B4-18). Other recommendations already proposed include the adoption of IPCC factors for both corn and sugarcane crops (see response to comment B4-45).

The values for chemical/fertilizer use in the CA-GREET3.0 model were adopted from the ANL GREET1_2016 model which references a study by Wang e et al, 2012 (see Table 2).[27] Other well accepted research studies such as Seabra et al, 2011[28] have presented values (see Table 1) based upon a survey which support the fertilizer use quantities by the GREET1_2016 model (in reasonable proximity).

The commenter has suggested that nitrogen values in CA-GREET3.0 are also understated because they do not include nitrogen in the roots. In that regards, see response to comment B4-18.

Staff found the commenter’s discussion in Appendix E to be related to indirect emissions for ILUC estimates and revisions associated with Corn farming, and unrelated to nitrogen fertilizer use for sugarcane-derived ethanol.

B4-54f The commenter states that CA-GREET3.0 uses the same emission factor for truck transport in Brazil and California, even though Brazil should be higher. Staff acknowledges the issue brought forward by the commenter. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. When Brazilian sugarcane ethanol is transported in California to blending stations, and further distributed to refueling stations, local electricity is indirectly consumed in diesel fuel production. Staff acknowledges that the Brazilian electricity mix was previously applied to emissions from transportation and distribution of Brazilian sugarcane-derived ethanol in California after arrival at California ports. This has now been changed to the California electricity mix.

B4-54g The commenter states that CA-GREET3.0 uses simplified calculators for corn ethanol and sugarcane ethanol that contain several errors that will result in the CI for sugarcane to be understated and for corn to be overstated if left

[27] Michael Wang *et al,* 2012 *Environ. Res. Lett.* 7 045905.
[28] Seabra, J.E.A. et al, 2011. “Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use,”

uncorrected. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Staff modified CA-GREET3.0 and all Simplified CI Calculators to address the comments where appropriate. See responses to individual comments related to errors stated by the commenter (comments B4-18 and B4-51).

B4-54h The commenter repeats that the EER for electricity is far too high because the estimates were generated based on testing performed with accessory modes off. See response to comment B4-25e.

B4-54i The commenter repeats that the EER for electricity is too high because it is based on optimal temperature for battery efficiency, and not real world conditions. See response to comment B4-25a.

B4-54j The commenter repeats that the EERs for numerous vehicles are overstated. See responses to comments B4-25a through 25i.

B4-54k The commenter states that the Proposed Amendments do not allow CI reduction for dedicated renewable electricity unless the generation facilities are co-located with the fuel production facility, removing incentives for fuel producers to develop renewable sources for process energy. See response to comment B4-26.

B4-54l The commenter repeats that CARB should resolve the issues mentioned prior to certifying the EA and approving the Proposed Amendments to avoid unnecessary increases in GHGs. See response to comment B4-54g.

B4-55 The commenter correctly states that Attachment 2 includes a summary of environmental impacts and mitigation measures, but is not intended to be used as a mitigation, monitoring, and reporting program (MMRP); however, in response to this comment, changes to Attachment 2 in the Final EA have been made to better summarize CARB’s legal authority, or lack thereof, to implement mitigation measures at the project level. Introductory language has been included to the summary table found in Attachment 2 to illustrate that there is inherent uncertainty regarding what entity would have the lead agency authority to implement appropriate project-level mitigation. The following text has been added to page 1 of Attachment 2:

> <u>The Regulatory Setting in Attachment 1 includes applicable laws and regulations that provide protection of aesthetic resources. CARB does not have the authority to require implementation of mitigation related to new or modified facilities or infrastructure that would be approved by other State agencies or local jurisdictions. The ability to require such measures is</u>

> within the purview of jurisdictions with land use approval and/or permitting authority. Project-specific impacts and mitigation would be identified during the project review process carried out by agencies with approval authority. Recognized practices routinely required to avoid and/or minimize impacts to aesthetic resources include:

The following text has been added to pages 3 through 4 of Attachment 2:

> The Regulatory Setting in Attachment 1 includes applicable laws and regulations that provide protection of aesthetic resources. CARB does not have the authority to require implementation of mitigation related to new or modified facilities or infrastructure that would be approved by other State agencies or local jurisdictions. The ability to require such measures is within the purview of jurisdictions with land use approval and/or permitting authority. Project-specific impacts and mitigation would be identified during the project review process carried out by agencies with approval authority. Recognized practices routinely required to avoid and/or minimize impacts to agriculture and forest resources include:

The following text has been added to page 7 of Attachment 2:

> The Regulatory Setting in Attachment 1 includes applicable laws and regulations that provide protection of air quality. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is within the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would likely qualify as a "project" under CEQA, because they would generally need a discretionary public agency approval and could affect the physical environment. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA. Project-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices routinely required to avoid and/or minimize impacts to air quality include the following:

The following text has been added to page 9 of Attachment 2:

> The Regulatory Setting in Attachment 1 includes applicable laws and regulations that provide protection of air quality. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is within the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would likely qualify as a "project" under CEQA,

because they would generally need a discretionary public agency approval and could affect the physical environment. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA. Project-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices routinely required to avoid and/or minimize impacts to air quality include the following:

The following text has been added to page 12 of Attachment 2:

The Regulatory Setting in Attachment 1 includes applicable laws and regulations that provide protection of biological resources. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would qualify as a “project” under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices that are routinely required to avoid and/or minimize impacts to biological resources include:

The following text has been added to page 15 through 16 of Attachment 2:

The Regulatory Setting in Attachment 1 includes, but is not limited to, applicable laws and regulations that provide protection of cultural resources. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would qualify as a “project” under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices that are routinely required to avoid and/or minimize impacts to cultural resources include:

The following text has been added to page 20 of Attachment 2:

The Regulatory Setting in Attachment 1 includes applicable laws and regulations in regard to energy resources. CARB does not have the

<u>authority to require implementation of mitigation related to new or modified facilities and infrastructure that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would qualify as a "project" under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices that are routinely required to avoid and/or minimize impacts to energy resources include:</u>

The following text has been added to page 22 of Attachment 2:

<u>The Regulatory Setting in Attachment 1 includes applicable laws and regulations that provide protection of geology and soils. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would qualify as a "project" under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices that are routinely required to avoid and/or minimize impacts to geology and soils include:</u>

The following text has been added to page 24 of Attachment 2:

<u>The Regulatory Setting in Attachment 1 includes applicable laws and regulations that provide protection of geology and soils. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would qualify as a "project" under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices that are routinely required to avoid and/or minimize impacts to geology and soils include:</u>

The following text has been added to page 28 of Attachment 2:

<u>The Regulatory Setting in Attachment 1 includes applicable laws and regulations that apply to accident-related hazards and risk of upset. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would qualify as a "project" under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices that are routinely required to avoid upset and accident-related impacts include:</u>

The following text has been added to page 32 of Attachment 2:

<u>The Regulatory Setting in Attachment 1 includes applicable laws and regulations in regard to hydrology and water quality. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would qualify as a "project" under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices that are routinely required to avoid and/or mitigate hydrology and water quality-related impacts include the following:</u>

The following text has been added to page 35 through 36 of Attachment 2:

<u>The Regulatory Setting in Attachment 1 includes applicable laws and regulations that provide protection of hydrology and water quality. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would qualify as a "project" under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices that are routinely required to avoid and/or minimize impacts to hydrology and water quality:</u>

The following text has been added to page 40 of Attachment 2:

The Regulatory Setting in Attachment 1 includes applicable laws and regulations that provide protection of mineral resources. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would most likely qualify as a "project" under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices that are routinely required to avoid and/or minimize impacts to mineral resources include:

The following text has been added to page 42 of Attachment 2:

The Regulatory Setting in Attachment 1 includes applicable laws and regulations that pertain to mineral resources. CARB does not have the authority to require implementation of mitigation related to new or modified facilities and infrastructure that could be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities and infrastructure in California would qualify as a "project" under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices that are routinely required to avoid and/or minimize mineral resource impacts include:

The following text has been added to page 43 through 44 of Attachment 2:

The Regulatory Setting in Attachment 1 includes, but is not limited to, applicable laws and regulations that pertain to noise. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that could be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would qualify as a "project" under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project-specific impacts and mitigation would be identified during the environmental review by agencies with

<u>project-approval authority. Recognized practices that are routinely required to avoid and/or minimize noise include:</u>

The following text has been added to page 49 of Attachment 2:

<u>The Regulatory Setting in Attachment 1 includes applicable laws and regulations in regard to transportation. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would qualify as a “project” under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Project-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices that are routinely required to avoid and/or minimize construction traffic impacts include:</u>

The following text has been added to page 51 of Attachment 2:

<u>The Regulatory Setting in Attachment 1 includes applicable laws and regulations in regard to transportation. CARB does not have the authority to require implementation of mitigation related to changes to traffic patterns; these must be addressed by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA statutes. Local agencies with project-approval authority would need to consider changes in traffic patterns in their relevant traffic management plans, regional transportation plans, or other relevant documents. Recognized practices that are routinely required to avoid and/or minimize operational traffic impacts include:</u>

The following text has been added to page 52 through 53 of Attachment 2:

<u>The Regulatory Setting in Attachment 1 includes applicable laws and regulations that relate to utilities and service systems. CARB does not have the authority to require implementation of mitigation related to new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is under the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would qualify as a “project” under CEQA. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for</u>

compliance with CEQA statutes. Project-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. Recognized practices that are routinely required to avoid and/or minimize utility and service-related impacts include:

See responses to comments B4-56 through B4-59 for additional information related to the proposed mitigation measures compliance with CEQA.

B4-56 The comment states that Mitigation Measures B.1.a, B.2.a, among others, do not require specific mitigation measures to be performed. This is correct. Please see response to comment B4-44 for a discussion of the level of specificity required in the Draft EA.

B4-57 The commenter refers to several cases that address proper deferral of mitigation measures, which rely on the use of performance criteria. Various mitigation measures are listed in this comment, along with some quoted text, and a statement that no performance standards are articulated.

This Draft EA generally does not analyze site-specific impacts because the location of future facilities or other infrastructure that may be built in response to the Proposed Amendments is speculative. As a result, the impact conclusions in the resource-oriented sections of Chapter 4, Impact Analysis and Mitigation Measures, cover broad types of impacts, considering the potential effects of the full range of reasonably foreseeable actions undertaken in response to the Proposed Amendments. The mitigation measures presented in the Draft EA provide recognized practices that are routinely required to avoid and/or minimize environmental impacts. The mitigation measures are beyond CARB's authority and cannot be enforced by CARB. As such, many potentially significant impacts are considered in the Draft EA to be potentially significant and unavoidable. Due to the programmatic level of analysis associated with implementation of the Proposed Amendments, the Draft EA does not attempt to address project-specific details of mitigation as there is inherent uncertainty in the degree of mitigation that may ultimately by implemented to reduce potentially significant impacts (stated throughout Chapter 4 of the Draft EA). Thus, mitigation is discussed appropriately in the Draft EA and no changes to the document are necessary.

B4-58 The commenter states that several mitigation measures in Attachment 2 are inadequately defined. Attachment 2 presents a summary of the potential impacts and proposed mitigation measures for each resource area discussed in the document (see Table of Contents and the first paragraph on page 45 of the Draft EA). In response to this comment, and comment B4-55, revisions have been made to Attachment 2 to improve clarification. See response to comment B4-55 for a summary on in-text revisions made to Attachment 2.

B4-59 The commenter states that comments submitted in connection with the 2015 rulemaking for the LCFS regulation and the ADF regulation remain relevant and are provided. This comment is noted. Please see the response to the remainder of this comment letter below.

B4-60 The commenter expresses their significant concerns regarding the LCFS regulation and the Proposed Amendments. The commenter requests that staff augment the ISOR and its appendices to fully address and consider meaningful alternatives to the LCFS regulation and that the ISOR also address each of the other issues raised in their comments in a revised ISOR. As explained in responses comments B4-50 through B4-52, CARB staff has adequately considered alternatives in the rulemaking record as required by law. Pursuant to APA, CEQA, and other legal requirements, CARB staff have considered public comments submitted and responded to all comments in the record.

B4-61 The commenter refers to comments that address an analysis of Cap-and-Trade alternatives to the LCFS regulation. See responses to comments B4-65 and B4-66.

B4-62 The commenter refers to discussions related to inclusion of the certification of E15. See response to comment B4-51.

B4-63 The commenter refers to discussions related to biodiesel use in California under the LCFS program. See responses to comments B4-68 through B4-73.

B4-64 The commenter refers to discussion associated with potential impacts of new and modified facilities related to the LCFS regulation. The analysis presented in the Draft EA contains a good-faith effort to analyze air emissions associated with the Proposed Amendments. The air quality discussion is thorough, and includes a discussion of both short-term construction-related air quality impacts (Impact B.3.a) and long-term operational air quality emissions (Impact B.3.b). The long-term operational air quality emissions discussion includes several graphics to provide helpful information to the reader, as well as subsection that analyzes specific compliance responses associated with the Proposed Amendments. These subsections include: Increased Use of Biodiesel and Renewable Diesel, Increased Use of Other Air Quality Improving Low Carbon Fuels, Increased Feedstock and Finished Fuel Transportation Distribution, Increased Production of Biofuels and Implementation of Solar Steam Projects in California, Increased Use of Alternative Jet Fuel, Displacement of Fossil Propane with Renewable Propane, Health Impacts Analysis (a more detailed discussion of the health impacts analysis is provided in Chapter V of the staff report), and Local Emissions Impacts. This detailed analysis presents information at a level of specificity that is appropriate for this program-level document. While it may differ from the 2015 LCFS and ADF EA, it adequately presents an evaluation of the significant air quality impacts associated with the Proposed Amendments. No changes to the air quality analysis are required.

The commenter recommends modifying the LCFS regulation to withhold approval of new fuel production pathway CI values unless all significant environment impacts of a facility are adequately mitigated. Because the authority to determine project-level impacts and require project-level mitigation lies with land use and/or permitting agencies for individual projects, and the programmatic level of analysis associated with the Draft EA does not attempt to address project-specific details of mitigation, there is inherent uncertainty in the degree of mitigation that may ultimately be implemented to reduce potentially significant impacts (see this discussion throughout Chapter 4 of the Draft EA).

B4-65 The comment presents an overview of the alternatives presented in the Draft EA and ISOR, stating that the ISOR should include a comprehensive and consistent analysis of all suggested alternatives, focusing on the statutory requirement to achieve GHG emission reductions in the most cost effective manner. The ISOR contains an evaluation of alternatives consistent with Government Code Section 11346.2(b)(4). The Draft EA presents an evaluation of alternatives consistent with the CEQA Guidelines and Statutes. No changes to the document are necessary. The commenter generally complains that some (unidentified) criteria staff used to reject alternatives were subjective, arbitrary, and “lack foundation” in (unidentified) underlying statutes. It is difficult to respond to such a vague charge. Regarding the one rejection criteria that the comment specifies – achieving radical decarburization of fuels – see the scoping plans CARB and sister state agencies have developed pursuant to Health and Safety Code section 38561. See also Health and Safety Code section 44285.5, Public Utilities Code section 740.12, and Public Resources Code section 25000.5.

B4-66 The commenter correctly states that the Draft EA dismisses the WSPA alternative from detailed evaluation. The comment provides a quote that is not part of the Draft EA. See response to comment B4-50.

The commenter addresses alternatives recommended by Growth Energy related to the 2015 LCFS rulemaking process. The 2015 Rulemaking processes are beyond the scope of the Final EA analyzing the Proposed Amendments. While no further response is necessary, in the interest of comprehensive disclosure, staff is providing the following responses.

B4-68 The commenter states that it submitted extensive comments related to the NOx emissions impacts of biodiesel use in California during the rulemaking process for the ADF regulation and amendments to the LCFS regulation in 2015. The commenter further asserts that these comments were passed over and never disaffirmed, and that they are still applicable to the 2018 analysis of this issue.

Staff responded to all of Growth Energy's comments on the 2015 rulemakings in the Response to Comments (RTC) and Final Statement of Reasons (FSOR) for those rulemakings. The RTC and FSOR included responses to comments related to the analysis of NOx emissions from biodiesel blends used in California.

The commenter also states that the conclusion of CARB's analysis regarding biodiesel impacts on NOx emissions in Appendix G of the ISOR is based primarily on assumptions, and not substantial evidence in the record.

CARB's analysis and subsequent conclusions related to biodiesel impacts on LCFS NOx emissions are based primarily on substantial evidence in the record, including NOx emissions inventory data, reported historical biodiesel consumption, projections of biodiesel consumption, and a conservative estimate of the percentage NOx emission increase relative to conventional diesel from the scientific literature. CARB's analysis also utilized conservative assumptions that likely overstated LCFS NOx emissions due to biomass-based diesel. Please see comment B7-1 and response to comments B4-33 and B4-36 related to the use of conservative assumptions and overstatement of LCFS NOx emissions due to biomass-based diesel use.

The commenter states that Appendix G of the ISOR considers but then dismisses a regulatory alternative that would ensure that biodiesel use in California creates no adverse environmental impacts based on economic factors alone without providing adequate data to justify that assumption.

Please see response to comment 9-2 regarding the analysis of Alternative 3 in Appendix G of the ISOR.

B4-69 The commenter states that assumptions in the Draft EA related to NO_X emissions are not supported by evidence. Chapter V of the ISOR provides the sources of data and the methodology used to support the NO_X and $PM_{2.5}$ emission estimates (see second paragraph, page 59 of the Draft EA). Please see comments B4-70 through B4-73 for responses to detailed comments on this issue. Moreover, CARB has 50 years of experience analyzing and regulating the evolution of vehicles, engines, and fuels, giving CARB special expertise in projecting future developments.

B4-70 The commenter states that CARB previously recognized the Lammert study[29] as an outlier. Please see response to comment B4-39 related to available literature on emissions associated with biodiesel use in NTDEs with SCR.

The commenter states that CARB staff and CARB contractors have published studies demonstrating that SCR systems in NTDEs are ineffective much of the time due to low exhaust temperatures and suggests that when the SCR system efficiency is low, NTDE NOx emissions will be increased by use of biodiesel. Based on these studies, the commenter estimated the magnitude of potential NOx emissions increases from the use of unmitigated biodiesel in on-road NTDEs. The commenter makes numerous assertions about the validity of the NOx emissions results including: (1) Lammert shows very high SCR efficiency not useful in assessing actual-in-use emissions; (2) NOx emissions may not be detected because they are below the detection levels of the instruments, and (3) the analysis does not account for performance deterioration due to tampering, maintenance issues, and other practices that may limit SCR effectiveness. Please see response to comment B4-39 related to published studies showing the potential for biodiesel use in NTDEs to result in increased NOx emissions compared to conventional diesel and staff's analysis of the NOx emissions impact of biodiesel use in NTDEs based on these published studies.

The commenter also asserts that CARB's analysis of biodiesel NOx emissions in Appendix G of the ISOR should have relied on emissions inventory data from EMFAC2017, which addresses SCR operation issues in NTDEs (e.g., deterioration, tampering, and maintenance issues). Because EMFAC2017 is not yet approved by U.S. EPA, staff used the NOx emissions inventory data from the most recent U.S. EPA-approved version of EMFAC (i.e., EMFAC2014) in the analyses for Appendix G of the ISOR and the Environmental Analysis for the Proposed Amendments to the LCFS and ADF Regulations. Staff examined what effect using EMFAC2017 would have on the results, and found that the results change slightly in certain future years, but the overall conclusions are unchanged. As noted in response to comment B4-39, CARB conducted an analysis using the commenter's unlikely estimate of SCR efficiency.

B4-71 The commenter states that Appendix G and the EA should not rely upon the assumption that NOx reductions from use of renewable diesel will mitigate NOx increases from biodiesel. The commenter further asserts that there is nothing in the ADF regulation, LCFS regulation, or the Proposed Amendments that mandates the use of renewable diesel, or alternative jet fuel or the completion of solar steam projects, which are also claimed as other means of mitigating NOx emissions increases associated with the use of

[29] Effect of B20 and Low Aromatic Diesel on Transit Bus NOx Emissions Over Driving Cycles with a Range of Kinetic Intensity, SAE Int. J Fuels Lubr., 5(3). Lammert, Michael et al., November 2012.

biodiesel. See responses to comments B4-33, B4-36, and B4-40 related to the use of biodiesel, renewable diesel, alternative jet fuel, and solar steam projects as compliance options for the LCFS.

The commenter states that CARB has already taken credit for NOx reductions due to LCFS-attributed volumes of renewable diesel as part of the "Low-Emission Diesel" requirement of the agency's Mobile Source SIP Strategy. See response to comment B4-37 related to the Low-Emission Diesel Measure.

B4-72 The commenter asserts that Alternative 3 in Appendix G of the ISOR is the only approach that would ensure that there are no increases in NOx emissions associated with biodiesel use in California. As discussed in Section D.4.c of Appendix G of the ISOR, the proposed amendments to the ADF regulation project no future increases in LCFS-attributed NOx emissions due to biomass-based diesel use. A CEQA analysis must identify and focus on the "significant environmental effects" of the Proposed Amendments. (Pub. Resources Code § 21100(b)(1); 14 CCR § 15126(a), 15143.) A significant effect on the environment is defined as "a substantial, or potentially substantial, adverse change in the environment." (Pub. Resources Code § 21068 [italics added].) A proposed project that foregoes potential benefits, but causes no significant increase in emissions above the environmental baseline, is not a CEQA impact because the project does nothing to adversely change the existing environmental conditions.

The commenter asserts that CARB rejected Alternative 3 based on cost considerations only without quantifying increased costs for biodiesel or providing analysis showing that biodiesel use would decrease. The commenter also states that CARB's approval of four alternative formulations for NOx mitigated biodiesel blends demonstrates that they are economically viable and presents expected cost effectiveness information published by CARB related to the Volkswagen Environmental Mitigation Trust.

As stated above, a proposed project that foregoes potential benefits, but causes no significant increase in emissions above the environmental baseline, is not a CEQA impact because the project does nothing to adversely change the existing environmental conditions. Furthermore, although CARB has certified several new NOx mitigation additives, CARB's evaluation of these additives does not consider economic costs, requiring these additives would still increase costs associated with biodiesel compared to not requiring them. Costs of NOx mitigation additives may be lower than what staff estimated in the initial adoption of the ADF regulation, but they still add a cost that, in the case the amendment does not require them, is unnecessary.

The commenter's comparison of the Volkswagen mitigation to a rejection of an alternative rulemaking approach is an inappropriate comparison and does not form the basis for rejecting Alternative 3; enforcement and new rule development are two different enterprises. Finally, staff's analysis of Alternative 3 included both environmental and economic considerations. Please also see response to comment 9-2 regarding the analysis of Alternative 3 in Appendix G of the ISOR.

B4-73 The commenter states that CARB's discussion of the VNRM in Appendix G of the ISOR does not specify the amount of NOx emissions that will be mitigated, the source of the funding, specifics regarding the types of projects that will be funded, how the agency will ensure that funding is actually made available, or how the projects will actually be implemented. See response to comment B4-3 related to the design and implementation of the VNRM and Section D.4.a of the Final NOx Disclosure Discussion.

B4-74 The commenter addresses the air quality analysis in the Draft EA, noting that it differs from the analysis presented for the 2015 LCFS EA. Please see response to comment B4-64.

B4-101 The commenter suggests that delivery reorganization of an LCFS market participant, POET, has likely generated additional carbon emissions. See response to comment B4-22.

B4-108 The commenter mentions the Draft EA and suggests that the Proposed Amendments inaccurately assess ILUC. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure regarding the LCFS approach to ILUC, see response to comment B4-20.

Comment Letter ECOENGINEERS1_B5 Responses

B5-13 The commenter commended CARB on its vision to incentivize avoided methane emissions for RNG from dairy digesters. Staff appreciates the support of CARB's efforts to reduce methane.

B5-14 The commenter asked if the carbon intensity score will be impacted if the dairy has a spill event. Staff recognizes the importance of regulatory clarity to support project development. If the commenter intended the term "spill event" to refer to an unanticipated leak or spill that could have other, non-GHG related impacts (e.g., impacts to groundwater quality), then staff's response is that only GHG emissions are considered in the determination of a fuel's carbon intensity score. The LCFS Dairy Pathway only includes the eligibility and quantification requirements of the Compliance Offset Protocol for Livestock Projects, Chapter 3.7. The LCFS method of determining CI relies on 24 months of operational data; in the event of an unanticipated release of methane, the pathway holder must accurately report the greenhouse gas emissions that occurred over the operational data period. If the certified CI is determined to have been exceeded, CARB will investigate and determine the appropriate adjustment to the certified CI and number of credits issued.

B5-15 The commenter asked if these projects need to be enrolled in the California Cap-and-Trade Program in order to participate in the LCFS. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Beginning in 2019, a dairy or livestock manure digester project does not need to participate in the California Cap-and-Trade Program in order to obtain a certified fuel pathway under the LCFS. Prior to 2019, the LCFS will utilize portions of the existing quantification and verification framework of the Cap-and-Trade Program's Compliance Offset Protocol Livestock Projects to streamline verification of such projects under both programs. Under the amended LCFS regulation, an existing or new dairy digester project applicant can apply for a fuel pathway with a minimum of three months of operational data and must adhere to the LCFS regulation's requirements to obtain third-party verification.

B5-16 The commenter asks how the Cap-and-Trade reporting schedule matches up against a quarterly LCFS reporting schedule. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Under the LCFS, credits are generated at the close of each quarter based on reporting fuel transactions for the preceding quarter, and the certified CI. Pathway CI values are determined on the basis of past performance, which is assumed to be representative of steady-state fuel production operations. Both the CI and transactions (quantities) are verified at the end of the calendar year, after credits have been issued.

In addition, the LCFS and Cap-and-Trade use different reporting periods: the LCFS operates on a calendar year, while the Compliance Offset Protocols allow for any 12-month period. This means that a livestock project that is transitioning from Offset credit generation to LCFS credit generation may need to obtain an additional verification statement to cover its initial January-December LCFS reporting period.

B5-17 The commenter commended CARB on allowing low-carbon crude to participate in the LCFS program and urged staff to take a similar view for corn ethanol. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Staff acknowledges support for facilitating the participation of low-carbon crude in the LCFS. As for the comment to consider using local (i.e., farm level) or regional farming practices, staff believes it is currently challenging to monitor and verify local/regional farming practices. Any provision to include farm-specific or applicant specific inputs for farming practices would entail significant increase in application review and processing times, potentially risking delays of loss of LCFS revenue for applicants when certifications are delayed. Staff is, therefore, not considering the inclusion of site-specific option for agricultural inputs at this time, but may consider inclusion of such options in the future if streamlined quantification and verification can be proposed.

Comment Letter STI1_B7 Responses

B7-1 The commenter states that CARB has likely overestimated potential increases in LCFS-attributed NOx emissions to due biodiesel use and provides a supporting analysis. CARB agrees with the commenter’s analysis and conclusions related to CARB’s methodology for attribution of biomass-based diesel use in California to the LCFS and the impact of this methodology on the estimated potential historical increase in LCFS-attributed NOx emissions due to biomass-based diesel use relative to conventional diesel use.

Comment Letter UCLA1_B8 Responses

B8-10 Staff thanks the commenter for the legal perspective on the LCFS interactions with Cap-and-Trade, and interjurisdictional linkages. Staff believes the provided comments are not within the scope of the present rulemaking because the issues discussed in the comment were not related to the proposed revisions or included in the notice of changes.

Comment Letter CAF2_FF2 Response

FF2-0 The commenter suggests that bifurcation of the ADF NOx mitigation sunset could increase criteria pollutant exposure in areas of high off-road vehicle populations, presumably due to decreased access to and use of B20 and corresponding increases in conventional diesel use. Staff disagrees with the commenter's suggestion that access to B20 would likely be reduced for off-road applications following the sunset of in-use requirements for biodiesel in the on-road sector. Because diesel fuel for on-road and off-road applications is already segregated to accommodate the road tax exemption for off-road vehicles and equipment, no additional tankage or rail cars are reasonably likely be needed to support staff's bifurcation proposal. For the same reason, no additional costs related to additional storage capacity would likely be incurred to store additized B20 for off-road applications following the sunset of in-use requirements for on-road vehicles. Therefore, access to B20 would not be likely to be reduced, and a decrease in off-road B20 volumes in any portion of the diesel market, and any associated increases in criteria pollutants, would not be reasonably foreseeable.

Comment Letter NBBCABA3_FF4 Responses

FF4-9 The commenter expresses that they have not been able to find published literature regarding emissions and public health impacts for co-processed fuels and are not convinced that the environmental and public health impacts of co-processing should be assumed to be positive. Co-processing fuel has been rewarded under prior versions of the LCFS and staff's Proposed Amendments do not significantly change the approach to such pathways. Under the staff proposal, pathways are evaluated as Tier 2 pathways subject to all requirements per Section 95488.7. The stated requirements are robust and adequate to model co-processing pathways since staff has routinely used the Tier 2 framework to model complex pathways in the LCFS. Also, a complete refinery analysis is not required since only a few process units need to be considered for co-processing applications. The analysis includes both baseline and project operation to determine project specific GHG emissions. In addition, GHG emission calculations require applicants to provide all necessary process and energy data including information to include potential indirect effects. To accommodate stakeholder comment related to redaction limiting public review of pathway details, staff is committed to publishing comprehensive details while accommodating confidentiality of applicant's process information.

Staff has completed a series of public workshops to highlight quantification and GHG emissions calculations for two refinery process units. Draft documents published provide preliminary steps in the quantification of renewable content and emissions from co-processing. Staff is in the process of reevaluating all methods for quantifying renewable content in co-processed fuels, including C14 analysis. Through a series of workshops in the future, staff is expected to update our quantification framework under the Tier 2 process for evaluating co-processing pathways by incorporating comments from stakeholders and experts. Additional co-processing workshops will be conducted after the second Board Hearing in 2018. Staff will continue to engage with stakeholders in future Work Group meetings to firm up the stated requirements.

The LCFS defines renewable co-processed fuels as renewable hydrocarbon fuels and are therefore exempt from the ADF regulation. Evaluation of emissions, fuel specifications and technical properties are outside the scope of the current LCFS rulemaking, however co-processed fuels are expected to meet the applicable fuel specifications when they are delivered to California.

Since co-processing produces alternative transportation fuels with low carbon fuels (or blendstocks), to incentivize commercialization of large-scale production of such fuels, it is not appropriate to limit the credits to no more than 20 percent of a refiner's obligation. Doing so could potentially limit investments by refineries to commercialize co-processing. Periodic updates to the LCFS program will offer an opportunity to revisit this issue and necessary adjustments will be considered based on experience with co-processed fuel volumes supplied to the program.

FF4-11 The commenter states that when bio-based feedstocks are comingled with fossil feedstocks, refiners should supply CARB with enough verifiable information to enable a full assessment of the indirect effects of co-processing on other refinery operations. See response to comment FF4-10.

Comment Letter FHR2_FF9 Response

FF9-1 The commenter states that greenhouse gases and other pollutant emissions associated with the construction of hydrogen fueling and electric vehicle charging stations should be included within the EA, and that the revised EA should be circulated. Recirculation is required when “significant new information” is added to the Draft EA, such that the public is deprived” of a meaningful opportunity to comment upon a substantial adverse environment effect or a feasible way to mitigate or avoid such an effect” (CEQA Guidelines Section 15088.5[a]). As stated in CEQA Guidelines Section 15088.5(a), “significant new information” requiring recirculation includes:

(1) A new significant environmental impact resulting from the project or from a new mitigation measures proposed to be implemented.
(2) A substantial increase in the severity of an environmental impact, unless mitigation measures are adopted that reduce the impact to a less-than-significant level.
(3) A feasible project alternative or mitigation measure considerably different from others previously analyzed, which would clearly lessen the environmental impacts of the project, but the project’s proponents decline to adopt it.
(4) The draft EIR was so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded.

The following discussion addresses the potential for changes to the Draft EA to result in new significant environmental impacts or a substantial increase in the severity of an environmental impact. No feasible project alternatives or mitigation measures were recommended during the review periods. The EA provides a thorough analysis of the environmental effects of the project and adequately meet CEQA requirements.

Governor Brown signed Executive Order B-48-18 (EO B-48-18) on January 26, 2018, to boost the use of ZEVs, electric vehicle charging infrastructure, and hydrogen refueling infrastructure in California. EO B-48-18 calls for a new Statewide target of 250,000 vehicle charging stations (including 10,000 direct current fast chargers [DC fast charging] stations) and 200 hydrogen refueling stations by 2025 to provide service to a fleet of 5 million ZEVs by 2030. This action builds on past efforts to boost ZEVs, including: legislation signed last year and in 2014 and 2013; adopting the 2016 Zero-Emission Vehicle Plan and the Advanced Clean Cars program; hosting a Zero-Emission Vehicle Summit; launching a multi-state ZEV Action Plan; co-founding the International ZEV Alliance; and issuing Executive Order B-16-12 in 2012 to help bring 1.5 million zero-emission vehicles to California by 2025.

Executive Order B-48-18 includes the following list of actions, which may be used to reach Statewide targets:

- Update the 2016 Zero-Emission Vehicle Action plan to help expand private investment in zero-emission vehicle infrastructure, particularly in low income and disadvantaged communities.
- Recommend actions that boost zero-emission vehicle infrastructure to strengthen the economy and create jobs in the State of California.
- Recommend ways to expand zero-emission vehicle infrastructure through the Low Carbon Fuel Standard Program.
- Support and recommend policies and actions that make it easier for people to install electric vehicle chargers in their homes and businesses.
- Ensure electric vehicle charging and hydrogen fueling are affordable and more accessible to all drivers.

To be consistent with EO B-48-18, the first 15-day changes included a new Zero-Emission Vehicle Fueling Infrastructure Pathways provision that strengthens the possible compliance response called out in the original EA of building ZEV infrastructure (hydrogen stations and charging stations). These infrastructure credits do not constitute "significant new information" that create a "substantial adverse environment effect or a feasible way to mitigate or avoid such an effect," therefore recirculation is not required.

To clarify this for the reader, Page 32 of the EA has been modified as follows:

<u>9. Zero-Emission Vehicle Fueling Infrastructure Pathways</u>

<u>Staff is proposing to credit zero-emission vehicle (ZEV) fueling infrastructure on the basis of the fueling station capacity for both hydrogen refueling infrastructure and DC fast charging infrastructure. The proposal is responsive to the Governor's Executive Order 8-48-18, direction in Board Resolution 18-17, and stakeholder comments. Like other aspects of the LCFS program, this amendment is intended to support development of ZEV infrastructure and is designed to sunset after an initial period of enhanced support for ZEV infrastructure build-out. The maximum quantity of infrastructure credits issued will be capped at 2.5 percent of overall program deficits for each category (2.5 percent for the hydrogen station provision and 2.5 percent for the fast charging provisions, for a maximum of 5 percent of total deficits across both).</u>

It is described again under Section 2.G.3.c.ii, with new text shown as <u>underline</u>.

The Draft EA identifies construction and operation of additional hydrogen stations and electric vehicle (EV) charging stations as a compliance response, as discussed in Section 2.G.2.G, “Additional Infrastructure Needs,” Section 2.H, “Summary of Compliance Responses,” and throughout Chapter 4 (e.g., see the first paragraph under Impact B.1.a: Short-Term Construction-Related and Long-Term Operational Impacts on Aesthetics).

The Draft EA included compliance responses that included EV charging stations and hydrogen refueling stations in Section 2.G.4.c, “Additional Infrastructure Needs” and Section 2.H, “Summary of Compliance Responses.” The environmental impacts of the construction and operation of these compliance responses are described throughout Chapter 4 (e.g., see the first paragraph under Impact B.1.a: Short-Term Construction-Related and Long-Term Operational Impacts on Aesthetics). Thus, there would not be a new significant environmental impact related to crediting of ZEV fueling infrastructure pathways.

The infrastructure provision is not a mandate, as a result the number and location of stations and chargers that would be constructed as a direct result of LCFS crediting for ZEV infrastructure is not reasonably foreseeable. However, these would likely occur within footprints of existing facilities, or in areas with existing zoning that would permit the development of manufacturing or industrial uses. In addition to the potential generation of LCFS credits, many factors and considerations influence the decision of when are where to build new ZEV infrastructure, including:

- State grant funding, including AB 8 grant funding
- Funding from case settlements
- Funding from public and investor owned utilities
- Location and access to customers/potential customers
- Rental and site acquisition costs
- Local jurisdictions’ (cities, counties) plan designations, zoning, support and permitting restrictions
- ZEV rollout projections
- Financing availability
- Fuel availability
- Electrical grid constraints and need for upgrades
- Average utilization rate for nearby stations/chargers
- Whether the facility would see regular fleet use at a charging/fueling station (e.g. parcel carriers)

The scope of analysis in the EA is intended to help focus public review and comments on the Proposed Amendments, and ultimately to inform the Board of the environmental benefits and adverse impacts of the proposed action prior to Board action. The analysis specifically focuses on potentially significant adverse and beneficial impacts on the physical environment resulting from reasonably foreseeable compliance responses to proposed changes to existing State regulations regarding fuel standards. The analysis addresses a broad market-based regulatory program necessitating a general level of detail; however, the EA makes a good-faith effort to evaluate significant adverse impacts and beneficial impacts of the regulatory program and contains as much information about those impacts as is currently available without speculation.

As discussed above, the decision to construct and operate ZEV fueling infrastructure would be based on many factors, one of which is the ability to generate LCFS credits. Additionally, the decision to locate new stations would depend on many other factors beyond CARB's jurisdiction, such as city or county land use plan and zoning designations, local government support or permitting restrictions, whether the grid requires substantial upgrades to support high power stations. Thus, attempting to determine the ultimate number and precise locations of new ZEV fueling infrastructure projects directly related to the proposed LCFS crediting incentives is not feasible. The Final EA continues to provide an appropriately broad level of environmental impact analysis. It would be speculative to determine whether new crediting procedures would cause a substantial increase in the severity of environmental impacts described in the Draft EA.

Therefore, recirculation of the Draft EA is not necessary, because there are no new significant environmental impacts or impacts of greater severity than previously disclosed.

FF9-7 The commenter suggests that the ZEV infrastructure capacity crediting provisions added to the amendments as a modification to the original proposal may cause environmental impacts that were not adequately analyzed in the draft EA. Consistent with the requirements of CEQA, CARB staff has prepared a Final EA that has been modified as indicated to indicate changes to the draft EA. As the Final EA discloses, CARB staff considered potential environmental impacts related to the addition to the proposal of the ZEV infrastructure capacity crediting provisions, and concluded that the addition did not add or intensify impacts related to potential compliance responses disclosed in the draft EA, nor result in any of the circumstances requiring recirculation of the analysis as set forth in section 15088.5 of the CEQA Guidelines. That determination was supported by substantial evidence in the administrative record.

Comment Letter UNICA3_FF38 Response

FF38-2 The commenter expresses concern that CARB continues to insist on the notion of back-haul penalties for maritime transportation of sugarcane ethanol to California. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. Global transport via ocean tankers has been detailed in a 2017 report.[30] The report highlights that more than 45 percent of ocean tankers hauling commodities return empty. Other reports provided by stakeholders for freight transport in the United States also confirm empty back-haul for most shipping modes.[31] It would be a significant burden to staff and third-party verifiers to check the manifest of every ocean tanker hauling ethanol from Brazil to California. To ensure consistency in accounting of GHG emissions from fuel transport to California, staff is including empty back-haul emissions for all modes of transport.

In consultations with stakeholders, staff has concluded there is inconclusive evidence to support non-empty back-haul leg for all modes of freight transport related to production and delivery of transportation fuels. To ensure 100 percent compliance of non-empty back-haul leg of transportation entails a significant burden on staff and third-party verifiers. Staff, therefore, has included appropriate back-haul emissions for all modes of transport, both for feedstock and finished fuel and represents a conservative approach in estimating such emissions.

[30] Geography, search frictions and endogenous trade costs, (No. w23581). National Bureau of Economic Research. Brancaccio, G., Kalouptsidi, M., & Papageorgiou, T. (2017).
[31] Analysis of Railroad Energy Efficiency in the United States, MPC Report No. 13-250. Upper Great Plains Tranpsortation Institute. Tolliver et. al. (2013).

Comment Letter CRF2_FF42 Response

FF42-2 The commenter expresses concern that the Proposed Amendments will send a message that the State will ignore CI reduction if it results from “disfavored biofuels” and thereby miss out on the pollution and health benefits associated with these biofuels. Staff proposed Hydrogen Refueling Infrastructure (HRI) crediting and Direct Current (DC) Fast Charging Infrastructure (FCI) crediting provisions to support development of Zero Emission Vehicle (ZEV) refueling infrastructure in California. The proposal is in line with the Governor's Executive Order 8-48-18, based on the direction provided to staff in Board Resolution 18-17, and in response to stakeholder comments. The Proposed Amendments are intended to support development of ZEV infrastructure in addition to the other state efforts to help achieve the Executive Order’s goal of installing 200 hydrogen refueling stations and 10,000 DC fast chargers by 2025. The Proposed Amendments would support ZEV refueling infrastructure development critical to promote ZEV adoption to help achieve state’s ZEV targets which in turn would help achieve state’s long-run air quality and GHG emissions reduction goals.

The Proposed Amendments are designed so the infrastructure credits decline over years as the overall fuel throughput increases with growing ZEV population in California with a limited crediting of 15 years under HRI provisions and 5 years under FCI provisions. Further, staff proposed the infrastructure for each category would be capped at 2.5 percent of the overall program deficits (i.e., 2.5 percent for HRI provision and 2.5 percent for FCI provision), limiting the total infrastructure credits up to 5 percent of total deficits in the LCFS program. Staff updated the GHG and air quality emissions impacts modeling to include the infrastructure credits and released the results of this analysis with the Second Notice of Public Availability of Modified Text and Availability of Additional Documents and Information (see Figure IV-1 in Attachment G to the Second Notice). While the inclusion of infrastructure credits does slightly reduce the GHG benefits of the proposed regulation relative to the original proposal described in the ISOR, the GHG and air quality emission reduction benefits of the Proposed Amendments are still substantial relative to both the 2016 baseline and the business-as-usual scenario.

Comment Letter GROWTHENERGY2_FF56 Response

FF56-6 The comment states that the Draft EA should be revised and recirculated based on the change in the nature of the project and the potentially significant environmental effects resulting from the implementation of the proposed modifications. See response to comments FF9-1 and FF56-25.

FF56-23 The comment states that development of capacity crediting pathways for DC fast charging and hydrogen refueling stations represents a wholesale change in the way the LCFS is structured, and that the modification is beyond the scope of the original notice of rulemaking. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. The modifications are within the scope of the notice, and CARB staff has gone beyond APA requirements to discuss them with stakeholders. As commenter notes, in addition to inviting written public comment on these proposed modifications to the original amendment proposal consistent with APA requirements, CARB invited additional public discussion of the modifications at two public workshops. At those workshops, CARB staff openly discussed with stakeholders that these pathways represent a targeted and carefully limited departure from the past incentive structure of the LCFS. But, as explained in response to comment FF9-1, the development of these pathways is also a logical outgrowth of the rule pursuant to gubernatorial executive order and board direction to explore new ways of incentivizing particular low carbon fuels. With the proposed infrastructure crediting provisions, the LCFS continues to create a strong incentive for all low carbon fuels and innovation, while adding additional incentive for actions related to ZEV infrastructure (buildout of hydrogen stations and DC fast chargers) that were recognized in the Draft EA, the Notice of Public Hearing related to the rulemaking, and the Initial Statement of Reasons. See response to comment FF9-1.

FF56-24 The comment asserts that allowance of generating and calculating credits for ZEV fueling infrastructure pathways constitutes significant new information under CEQA, and that the EA should be recirculated. The comment does not identify any new or more significant environmental impacts or otherwise raise any significant environmental issues that would result from the Proposed Amendments. Therefore, this comment does not require a response. Nevertheless, in the interest of comprehensive disclosure, staff responds here as follows. See response to comment FF9-1.

The comment expresses concerns that by providing credits for infrastructure and capacity, CARB would be lessening the value of credits for other lower CI fuel and potentially displacing lower CI fuels with alternative fuels with higher

CI values. The maximum quantity of infrastructure credits issued would be capped at 2.5 percent of overall program deficits for each category (2.5 percent for the hydrogen station provision and 2.5 percent for the fast charging provisions, for a maximum of 5 percent of total deficits across both) so the overall program impact from this provision is limited. Further, staff's economic modelling scenarios suggest that the proposed amendment scenario, that includes the infrastructure credits, provides a more stable long-term credit price trajectory and greater total credit value (credit price multiplied by the number of credits) for some non-ZEV low carbon fuels (including starch ethanol) relative to the baseline scenario. Finally, as noted above, the comment does not identify adverse environmental impacts resulting from the proposed project. A CEQA analysis must identify and focus on the "significant environmental effects" of the Proposed Amendments. (Pub. Resources Code § 21100(b)(1); 14 CCR § 15126(a), 15143.) A significant effect on the environment is defined as "a substantial, or potentially substantial, adverse change in the environment." (Pub. Resources Code § 21068 [italics added].) A proposed project that foregoes potential benefits, but causes no significant increase in emissions above the environmental baseline, is not a CEQA impact because the project does nothing to adversely change the existing environmental conditions.

FF56-25 The comment states that the EA was not modified to include separate sunset dates for the biodiesel NOx mitigation requirements for on-road and non-road diesel vehicles and engines. CARB modified the Draft EA to reflect the proposed bifurcation of biodiesel in-use requirements for on-road and off-road sectors. The Proposed Amendments, including the modification to the amendment to the ADF regulation, still result in NOx emissions benefits compared to both the baseline and BAU scenarios, and do not change staff's significance conclusions presented in the Draft EA. As noted above, a significant effect on the environment is defined as "a substantial, or potentially substantial, adverse change in the environment." (Pub. Resources Code § 21068 [italics added].) A proposed project that foregoes potential benefits, but causes no significant increase in emissions above the environmental baseline, is not a CEQA impact because the project does nothing to adversely change the existing environmental conditions.

The comment also states that CARB's assumption that there is no increase in NOx emissions from NTDEs is not supported by substantial evidence. Staff also considered the scenario presented by the commenter (i.e., that the SCR system in NTDEs is ineffective 70 percent of the time) in the NOx emissions analysis for the Final NOx Disclosure Discussion and the Final EA. Please see response to comment B4-39 regarding staff's analysis of NOx emissions for NTDE SCR systems with reduced effectiveness.

The comment states that there is nothing in either the Proposed Amendments or the Proposed Modifications that, following the sunset date for one category of vehicles, would prohibit biodiesel without mitigation to be introduced into the other category of vehicles or engines that have not yet reached the sunset date. The proposed ADF amendment requires the continued use of NOx mitigation for biodiesel blends above the NOx control level (usually B5) in off-road equipment when the biodiesel in-use requirements sunset for on-road vehicles. The cost differential between on-highway fuel taxes and NOx mitigation additives, on a per gallon basis for biodiesel, is likely a sufficient deterrent to using un-mitigated on-road biodiesel in off-road equipment. Staff coordinates with the California Department of Tax and Fee Administration and will monitor fuel tax data for biodiesel in on- and off-road applications. If these data indicate potential issues with the proposed sunset provision design, CARB will take appropriate action.

FF56-26 The comment states that the EA should be revised and recirculated due to project changes that would allow for the generation of credits associated with hydrogen and DC fast charging facilities and disaggregating the sunset provisions. Please see response to comments FF9-1 and FF56-25.

FF56-27 The comment states that CARB did not modify the EA or otherwise discuss the potential environmental effects of the proposed changes included in the first 15-day modifications to the regulation. See response to comment FF9-1 and FF56-23.

FF56-28 The commenter asserts that the proposed modifications are inconsistent with CARB's defined project objectives, AB 32, and SB 32. Please see response to FF42-2.

FF56-29 The commenter recommends consideration of the E15 Alternative. See response to B4-51.

FF56-31 The commenter suggests that CARB undertake peer review of several questions related to the Proposed Amendments. See response to B4-17.

FF56-32 The comment refers to previously submitted comments on the Proposed Amendments, recommending that suggested changes are incorporated into the final version of the Regulation. Written responses to comments must describe the disposition of significant environmental issues raised (CEQA Guidelines Section 15088); however, the inclusion of recommended changes to the Draft EA or proposed project is not required. The Board and staff have reviewed all comments submitted during the public review period and will consider recommended changes described in this comment letter.

FF56-50 The commenter states that the LCFS regulation has resulted in increased and unmitigated NOx emissions from biodiesel use since its inception and there is nothing in the Proposed Amendments that suggest these emissions would be mitigated through the payment of funds to local air districts for NOx mitigation projects. Please see response to B4-33 related to NOx impacts due to biomass-based diesel use attributed to the LCFS and the implementation and design of the VNRM and Section D.4.a of the Final NOx Disclosure Discussion.

FF56-51 The commenter states that the proposed mitigation for continuing NOx emissions is not consistent with CEQA. The commenter also states that the ISOR's conclusions are based on assumptions concerning industry's use of renewable diesel and alternative jet fuel, and the development of solar steam projects, none of which are required to occur, and all of which are speculative. Please see response to B4-33 related to the use of renewable diesel and alternative jet fuel and the development of solar steam projects as compliance options.

FF56-52 The commenter suggests that the LCFS will result in the construction of new or modified facilities for alternative fuels. See response to B4-33.

FF56-53 The commenter suggests that the LCFS will result in fuel shuffling, which will increase emissions. See response to B4-22.

FF56-65 The comment states that the Draft EA should consider the environmental effects of providing credits for ZEV infrastructure. See response to comment FF9-1.

FF56-67 The comment states that imposing separate sunset dates for biodiesel mitigation requirements under the ADF regulation may lead to increases in NOx emissions that are not accounted for in the EA. See response to comment FF56-25 related to NOx emissions impacts related to bifurcation of biodiesel in-use requirements in the ADF regulation.

Comment Letter CAF3_SF14 Response

SF14-1 The commenter asserts that CARB provides no reasonable basis to bifurcate on-road and off-road sunset provisions in the ADF regulation, based on a 2016 study showing NOx emissions increases for biodiesel use in SCR-equipped engines and another study indicating that NTDEs do not provide the expected NOx reductions. The 2016 study cited by the commenter was not included in staff's quantitative analysis of NOx emissions impacts because it did not satisfy staff's study selection criteria, as outlined in the 2015 ADF staff report.[32] The 2016 study was performed using a chassis dynamometer. Staff's analysis of emissions impacts associated with biodiesel and renewable diesel only included studies performed using an engine dynamometer because engine dynamometers are computer-controlled, and thus able to get a more accurate representation of true fuel-to-fuel differences by eliminating variability due to manual operation. Based on the information and data reviewed, considered, and relied upon in staff's quantitative analysis of the impacts associated with bifurcation of the on-road and off-road sunset provisions of the ADF regulation, the proposed amendment to the ADF regulation, as modified, is expected to provide emissions benefits and health benefits compared to the current ADF regulation, as demonstrated in the Final EA (see Section 4.B.3) and the Final NOx Disclosure Discussion (see Section D.4.c). The 2016 study was not included in the quantitative analysis because it did not meet the study selection criteria, but it suggests that continuing study, currently underway by staff, of the effectiveness of biodiesel NOx emissions controls is warranted. Please also see response to comment B4-39.

The commenter references its June 2018 comment letter and restates that it does not support a bifurcation concept because of its potential adverse effect on NOx. Please see response to comment FF2-0.

[32] CARB. 2015. Proposed Regulation on the Commercialization of Alternative Diesel Fuels, Staff Report: Initial Statement of Reasons. January 2. Available at: https://www.arb.ca.gov/regact/2015/adf2015/adf15isor.pdf

Comment Letter CCAALACVAQ1_SF16 Response

SF16-5 The commenter expresses concern that the Proposed Amendments may impact the environmental benefits of the program. Please see response to comment FF42-2

Comment Letter GROWTHENERGY3_SF31 Response

SF31-5 The comment requests review of alternatives submitted in previous comment letters. See response to comment B4-50 and B4-52 for a discussion related to CEQA requirements for alternatives. Please see responses to comments B4-50 for additional discussion related to the WSPA Alternative and B4-51 for a discussion related to the E15 Alternative.

SF31-14bThe commenter says that CARB staff failed to analyze potential environmental impacts of the infrastructure crediting provisions. See response to FF9-1.

APPENDIX A

Comment Letters

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OP_CAF1_9

April 9, 2018

Mr. Sam Wade
California Environmental Protection Agency
Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: 2018 LCFS Rulemaking

Thank you for the opportunity to submit comments to the subject document. California Fueling prides itself in being a California based owned/operated business. We were the first company to obtain CARB approval of a NOX Mitigant, VESTA™ 1000, under the ADF. Our technology has advanced since this initial approval and we remain focused on developing more cost-effective market solutions to CARB's NOX Mitigation challenges.

Following are comments relating to two sections of the proposed rulemaking, both of which are particular to the ADF. Our comments are intended to bridge practical experience with rulemaking efforts so that the LCFS's proposed improvements can translate into viable market solutions. In addition, we seek to clarify certain viewpoints which may have been true in the past but require updating.

1. **Supplemental NOx Disclosure**

Section 3. b., page G-7

"During the rulemaking process, staff will continue to evaluate whether the sunset provision can be bifurcated for on-road vehicles versus off-road vehicles and equipment, which would result in an earlier anticipated sunset date for on-road vehicles while preventing any NOx increases above baseline."

Following are California Fueling's comments regarding "bifurcation": 9-1

The bifurcation concept has significant practical challenges. In today's marketplace, BXX blends are splash blended (as opposed to in-line blending). If the on-road ADF were to expire NOX Mitigant would not be required. Meanwhile, the off-road ADF would remain intact requiring NOX Mitigant. As a result, infrastructure challenges would surface. For example, when >B5 blends are splash blended "under the rack", NOX Mitigant is added to biodiesel in bulk storage tanks or in railcars (making it "additized"). Should under the rack blenders be required to "additize" biodiesel railcars or bulk storage tanks for off-road and not for on-road, they would be required to double the number of tanks, railcars, etc. This likely would not occur because of increased costs, limited asset availability, etc. and, as a result, off-road B20 volumes could be

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negatively impacted. The same would hold true for terminal blending given they too splash blend BXX in tankage, however, at present, terminals are only blending seasonal allowances which do not require NOX Mitigant.

Terminals represent the single largest opportunity to promote B20 blends, yet few are doing so. Terminal clients, or obligated parties, dictate BXX blend levels. In order for terminals to invest in BXX blending equipment and infrastructure, their clients would have to be willing to assume those costs. In a moving target scenario, (e.g. different on and off-road sunset dates), terminal clients will be less likely to invest the capital required to rack blend B20 because of the timing payback uncertainty.

Biodiesel represents one of the key opportunities for fossil fuel replacement. Given the amount of off-road diesel in California (~30-35% of the total diesel fuel consumed in California), a significant portion of the diesel market may be precluded from using biodiesel from a practicality perspective if a bifurcation concept was adopted. Off road diesel vehicles emit >250 tons per day of NOX emissions as well as additional particulate matter. The off-road diesel market could become one of the highest criteria pollutant emitting fuels if access to renewable fuel options is made difficult. Citizens of California in areas of high off-road vehicle populations face potential increased exposure of criteria pollutants should off-road B20 ADF volumes be negatively impacted because of bifurcation. 9-1 cont.

In summary, the current ADF applies to on and off-road BXX blends above seasonal allowances. However, if the on-road ADF sunsets, but the off-road ADF remained intact, the off-road B20 market would likely be negatively impacted because of the increased infrastructure requirements of supplying two fuel types.

2. **Supplemental NOx Disclosure**

F. ALTERNATIVES ANALYSIS

3. Description of Alternatives

c. Alternative 3: Require Mitigation for all Biodiesel Blends 9-2

"Staff analyzed a very similar alternative as part of the alternatives analysis for the LCFS regulations adopted in 2015.[196]"

In 2015, there was only one (1) CARB approved NOX Mitigant, di-tertiarybutyl peroxide (DTBP). In the last nine months, three (3) different NOX Mitigants have been approved by CARB. All recently approved options are far more practical and cost effective than DTBP. Any conclusions drawn from '15 premises should be updated to reflect the current state of the market especially given the opportunity to update the LCFS.

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3. ii. Discussion

"The future effects of requiring NOx mitigation of all biodiesel blends to the level of conventional diesel would be a likely increase in the use of additives, such as Di-tert-butyl peroxide or renewable diesel, to reduce NOx emissions associated with biodiesel use. This would increase the cost of biodiesel, which is currently one of the cheapest compliance options for the LCFS. The increased cost of biodiesel would likely reduce the incentive for its use, leading to a likely decrease in biodiesel consumption in California relative to projected levels for the project following the adoption of the Proposed Amendments. Because of this, greater quantities of other, more expensive fuels, including renewable diesel, would be necessary to replace credits that could otherwise be generated by biodiesel. Therefore, this alternative would make it more difficult and expensive to generate the average carbon intensity reductions and GHG benefits associated with the project following the adoption of the Proposed Amendments." 9-3

Prior to the implementation of the ADF's NOX Mitigation requirements on January 1, 2018, Renewable Diesel's (RD) use significantly increased versus biodiesel as a result of multiple factors including RD's declining CI versus biodiesels increasing CI, ease of use, etc. To weigh in on the economics of biodiesel versus RHD, one would have to consider a multitude of market factors. NOX Mitigants do increases biodiesel costs, however, those costs continue to decline as more products are approved. Assuming that an additive's cost would increase the cost of biodiesel such that it would make it uneconomical versus RD is not accurate. The conclusion that the alternative would be counterproductive to CI and GHG benefits is <u>not</u> accurate either.

4. iii. Environmental Impacts

The supposition that requiring NOX Mitigants would adversely impact biodiesel construction and expansion projects is inaccurate. From an in-state perspective, there's plenty of spare capacity available and production has been stable for some time. The further supposition that NOX Mitigation additive plants would have to be constructed is simply not true; no NOX Mitigant plants are under construction nor are any planned. Consequently, there's no negative impact to the environment as a result of NOX Mitigant manufacturing in California. 9-4

The premise that somehow use of NOX Mitigants, if required in all biodiesel blends, would negatively impact PM emissions as a result of decreased biodiesel use has no evidentiary support. Conversely, registered NOX Mitigants have been shown to improve PM emissions versus BXX blends without NOX Mitigants. 9-5

An alternate viewpoint exists. Should CARB require NOX Mitigants in all biodiesel blends, biodiesel use could be favorably impacted. As CARB knows, most BXX blending above seasonal allowances occurs "under the rack", which is a blending bottleneck. Conversely, B5 is blended 9-6

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state-wide at terminal racks and 70% of biodiesel use is B5. Implementation of NOX Mitigant at terminals, as a result of the removal of seasonal allowances, could open up more serious consideration of higher BXX blends being made available at terminals across the state. 9-6 cont.

The lack of additive infrastructure is a critical hurdle to increasing the use of biodiesel blends. CARB estimated NOX Mitigant equipment costs would be more than the additive itself ($0.12/gal for equipment vs an additive cost of $0.10/gal – Staff Report 10/23/13). Very little capital has been invested in terminal equipment to date. Removal of the seasonal allowances could change this very quickly. 9-7

The likelihood of terminals reversing course and moving away from BXX blending as a result of removing the seasonal allowances is not likely given terminal client benefits. A significant number of LCFS credits come as a result of B5 blends and most obligated parties rely on this source to generate credits. 9-8

Lastly, the dial down NOX Mitigant treat rates would ensure that when blending B5-B10 such blends would only incur a minimal additive treat cost expense (¼ to ½ that of B20). 9-9

We sincerely appreciate all of CARB's efforts to advance and clarify the LCFS. We look forward to working with CARB through the current rulemaking process.

Sincerely,

Patrick J. McDuff
CEO

CALIFORNIA
FUELING

OP_INNOSPEC1_51

innospec specialty chemicals

April 23, 2018

VIA ELECTRONIC SUBMISSION & UNITED STATES MAIL

Clerk of the Board
California Air Resources Board
1001 "I" Street, 23rd Floor
Sacramento, CA 95814

Re: Proposed Regulation on the Commercialization of Alternative Diesel Fuels

Dear Mr. Corey:

Innospec Inc. ("Innospec") appreciates the opportunity to comment on the California Air Resources Board's ("CARB") proposed amendments to (i) the low carbon fuel standard regulation (the "LCFS regulation") and (ii) the regulation on commercialization of alternative diesel fuels (the "ADF regulation"). Innospec submits these comments to provide CARB with its suggestions to help ensure the ADF regulation is effective in reducing emissions of oxides of nitrogen ("NOx") from projected increases in biodiesel usage.

Innospec is a global specialty chemicals business. Our Fuel Specialties unit is responsible for the development of fuel additive technology across the complete range of fuels, from petroleum-based, to coal and biofuels. As an entity engaged directly in the development of additives for alternative diesel fuels, Innospec has a strong interest in the development of additives that will help CARB achieve its goal of reducing criteria pollutant and greenhouse gas emissions.

A. Executive Summary

Innospec understands Appendix 1 to the ADF regulation approved in 2015 contained a typographical error in the amount of polycyclic aromatic content in the reference fuels used for testing fuel additives. Specifically, the table suggested applicants for new alternative fuel additives could use reference fuels with a polycyclic aromatic content of less than or equal to 10%, when the maximum level should have been 1.4%. Unfortunately, this error has a direct impact on NOx and PM emissions, because fuels with a higher aromatic content have been shown to require smaller amounts of additives to reduce such emissions. 51-1

Innospec appreciates the fact that CARB has recognized this problem, and is seeking to correct this issue in the current rulemaking. However, to ensure the LCFS

Innospec Fuel Specialties LLC
8310 South Valley Highway, Suite 350
Englewood, CO 80112
Tel: (303) 792 – 5554
Fax: (303) 792 – 5668
www.innospecinc.com

innospec
specialty chemicals

regulation and the ADF regulation will not result in increases in NOx emissions, it is important that CARB review additives previously certified under Appendix 1, and confirm whether those additives were certified using a reference fuel containing a polycyclic aromatic content of less than 1.4%. Likewise, CARB should consider further amendments designed to revisit the certification of any additive approved using a reference fuel with a polycyclic aromatic content higher than 1.4%. 51-1 continued from previous page, continues below

B. Regulatory Background

In 2009, CARB adopted the LCFS regulation to reduce the carbon intensity of transportation fuels used in California. During the rulemaking process for the original LCFS regulation, CARB staff recognized that the increased use of biodiesel incented by the LCFS regulation could result in an increase in NOx emissions. (See, e.g., ISOR, Appx. G at G-12.) As a result, CARB adopted the ADF regulation in 2015 "to require NOx-reducing measures, such as fuel additives, for biodiesel use above specified control levels." (*Id.*)

To ensure fuel additives would actually achieve the desired NOx reductions, and would not result in other negative environmental effects, the 2015 ADF regulation included in-use requirements for pollutant emissions control. These requirements are included in Appendix 1, which provides specifications for the certification of biodiesel additives, and emissions testing protocols. (ADF Regulation, Appendix 1, subds. (a)(2)(D), (a)(2)(F).) As part of the testing process, the ADF regulation requires tests using a "reference fuel" containing the properties and specifications identified in Subdivision (a)(2)(E), Table A-9. The Executive Officer may only certify additives that have complied with these rigorous testing requirements. (*Id.*, subd. (a)(2)(H).)

C. Maximum Polycyclic Aromatic Content of Reference Fuels

51-1 continued from above, continues to next page

The 2015 regulations contained a typographical error in Table A-9. In the 2015 regulation, Table A-9 incorrectly stated the reference fuel could include a maximum "Polycyclic Aromatic Content, Weight %" of 10%:

Innospec Fuel Specialties LLC
8310 South Valley Highway, Suite 350
Englewood, CO 80112
Tel: (303) 792 – 5554
Fax: (303) 792 – 5668
www.innospecinc.com

innospec specialty chemicals

Table A.9: Reference Fuel Specifications

Property	Test Method	Fuel Specifications
Sulfur Content	ASTM D5453-93	15 ppm maximum
Aromatic Hydrocarbon Content, Volume %	ASTM D5186-03(2009)	10 % maximum
Polycyclic Aromatic Content, Weight %	ASTM D5186-03(2009)	10 % maximum
Nitrogen Content	ASTM D4629-12	10 ppm maximum
Unadditized Cetane Number	ASTM D613-14, ASTM D6890-13be1, ASTM D7170-14; or ASTM D7668-14a	48 minimum
API Gravity	ASTM D287-12b	33 – 39
Viscosity at 40°C, cSt	ASTM D445-14e2	2.0 – 4.1
Flash Point, °F, minimum	ASTM D93-13e1	130
Distillation, °F	ASTM D86-12	
Initial Boiling Point		340 – 420
10 % Recovered		400 – 490
50 % Recovered		470 – 560
90 % Recovered		550 – 610
End Point		580 – 660

(ADF Regulation, Appendix 1, subdivison (a)(2)(E), Table A. 9 [emphasis added].)

The maximum Polycyclic Aromatic Content should have been listed as 1.4%, consistent with the existing standards adopted in 2004 for diesel reference fuel specifications. (*Cf.* 13 Cal. Code Regs., § 2282(g)(3)(A).) This was recognized in CARB's November 2017 ADF FAQs, No. 36, which states: 51-1 cont.

> **36. What CARB diesel reference fuel properties must be met for NOx control certification?**
>
> The reference CARB diesel must meet the specifications in Table A.9 of Appendix 1 in the ADF regulation, must be produced using normal refinery processes, including distillation and hydrotreating, but not cracking, and must not include any chemical blendstocks. ***Please note that the Polycyclic Aromatic Content listed in Table A.9 is a typo, it should be 1.4% maximum, not 10% maximum.***

(See Exhibit "A" at 8/9 [emphasis added].)

Increased aromatic or polycyclic aromatic content in a fuel has a direct effect on the amount of NOx and PM emissions associated with the combustion of a fuel. Specifically, the higher the aromatic content of a fuel when blended with biodiesel, the less additive, such as 2 ethyl-hexyl nitrate (2EHN), that is needed to reduce NOx emissions from the fuel. (See, e.g., Exhibit "A.") This affect is increased further with increased polycyclic aromatic content because it increases the number of aromatic rings. The effect is in part that fuels become more NOx neutral as aromatics increase and the dilution factor of 20% biodiesel could reduce polynuclear aromatics by 20%. In addition, the reference fuel itself would have higher baseline emissions and provide a lower barrier

Innospec Fuel Specialties LLC
8310 South Valley Highway, Suite 350
Englewood, CO 80112
Tel: (303) 792 – 5554
Fax: (303) 792 – 5668
www.innospecinc.com

innospec specialty chemicals

to passing the test. Thus, any additives that were approved based on the use of a reference fuel with a polycyclic aromatic content of greater than 1.4% could significantly undermine the efficacy of the additive in reducing NOx emissions associated with biodiesel.

For instance, Innospec understands CARB recently has certified additives based primarily on 2EHN. The Executive Orders for those additives are silent on the issue of whether the testing underlying the certifications using primarily 2EHN additives were performed using reference fuels with polycyclic aromatic content of less than or equal to1.4%. (See *id.*) This does not in fact appear to be the case. For example, one of the Executive Orders approved 2EHN additives with a minimum volume percent of 1,500 ppm (0.150), and having an NOx reduction of 0.9%. (See Executive Order G-714-ADF03 at 2.) This strongly implies that the reference fuel had a very high base line NOx which upon dilution polycyclic aromatics would be much lower. As such, to ensure the one of the fundamental underpinnings of CARB's environmental findings in this rulemaking relating to biodiesel is correct, CARB should confirm whether the testing for 2EHN based additives was performed using a reference fuel with a polycyclic aromatic content of less than or equal to1.4%. If not, CARB should review Executive Order G-714-ADF03 and confirm the appropriate minimum volume percent sufficient to reduce NOx emissions at the expected levels.[1] 51-1 cont.

CARB should also confirm any other biodiesel additive certified prior to the promulgation of the Proposed Amendments complied with the requirements for reference fuels contained in Appendix 1, Subdivisoin (a)(2)(E), Table A-9. (See, e.g., February 22, 2018, Executive Order G-714-ADF04; July 20, 2017, Executive Order G-714-ADF01.)

D. Proposed Amendments to Appendix 1, Subd. (a)(2)

To ensure the ADF regulation will achieve its purpose in reducing NOx emissions from biodiesel usage incented by the LCFS regulation, and to promote fairness for companies like Innospec that have attempted to comply with the rigorous testing requirements specified under Appendix 1, Subdivision (a)(2), CARB should also consider the following common sense modifications to the ADF regulation:

> (H) If the Executive Officer finds that a candidate fuel has been properly tested in accordance with (a)(2)(F) of this appendix, and makes the determinations specified in (a)(2)(G) of this appendix, then he or she shall issue an Executive Order certifying the alternative

---

[1] Page 3 of Executive Order G-714-ADF03 clarifies that CARB may revisit the 2EHN additives based on the use of an incorrect reference fuel: "CARB reserves the right in the future to review this Executive Order and the certification provided herein to assure that the certified fuel meets the standards and procedures of Title 13, California Code of Regulation, section 2293, et seq."

Innospec Fuel Specialties LLC
8310 South Valley Highway, Suite 350
Englewood, CO 80112
Tel: (303) 792 – 5554
Fax: (303) 792 – 5668
www.innospecinc.com

innospec specialty chemicals

diesel fuel or additive formulation represented by the candidate fuel. The Executive Order shall identify all of the characteristics of the candidate fuel determined pursuant to (a)(2)(C) of this appendix. The Executive Order shall provide that the certified alternative diesel fuel formulation has the following specifications: [1] a sulfur content, total aromatic hydrocarbon content, polycyclic aromatic hydrocarbon content, and nitrogen content not exceeding that of the candidate fuel, [2] a cetane number and API gravity not less than that of the candidate fuel, [3] any additional fuel specification required under (a)(2)(C) of this appendix, and [4] presence of all additives that were contained in the candidate fuel, in a concentration not less than in the candidate fuel, except for an additive demonstrated by the applicant to have the sole effect of increasing cetane number. Additionally the Executive Order shall contain a table mirroring Table A.5 in Appendix 1 (a)(1)(A) listing the required concentration of additive at each 5 percent interval of blend level, if applicable. All such characteristics shall be determined in accordance with the test methods identified in (a)(2)(C) of this appendix. The Executive Order shall assign an identification name to the specific certified biodiesel fuel formulation. <u>To the extent any alternative diesel fuel or additive formulation was certified by the Executive Officer based on testing that included the use of a reference fuel that no longer meets the Reference Fuel Specifications in Table A.9, such certification shall be suspended until such time as the applicant demonstrates compliance with Table A.9.</u> 51-1 cont.

Innospec strongly believes the above amendments are necessary to ensure biodiesel fuel additives actually achieve the desired reductions in NOx emissions from biodiesel usage. Without such protections, there is a significant danger that additives certified under the existing ADF regulation will not be used in volumes sufficient to reduce such NOx emissions.

Innospec appreciates the opportunity to submit comments on the ADF Regulation. If you have any questions regarding our comments, please contact David Daniels, Innospec's Director of Research & Development, at (303) 947-9405.

Respectfully Submitted,

David Jones
General Counsel
Innospec Inc.

Enclosure

Innospec Fuel Specialties LLC
8310 South Valley Highway, Suite 350
Englewood, CO 80112
Tel: (303) 792 – 5554
Fax: (303) 792 – 5668
www.innospecinc.com

Subcontractor Report

February 2003 • NREL/SR-510-31465

NO_x Solutions for Biodiesel

Final Report
Report 6 in a series of 6

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Exhibit "A"

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NREL Technical Monitor: K.S. Tyson

Prepared under Subcontract No. XCO-0-30088-01

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SUMMARY

This study has examined a number of approaches for NO_x reduction from biodiesel. Blending FT diesel at very high percentages can produce a NO_x neutral fuel. Lowering the base fuel aromatic content from 31.9% to 7.5% (nominally 10% aromatic fuel) was very successful at lowering NO_x. If all other factors are equal, and if the effect of aromatic content is linear, using a base fuel having 25.8% aromatics should provide a NO_x neutral B20 (relative to certification diesel having nominally a 30% aromatic content). The results also suggest that using kerosene as the base fuel could lead to a NO_x neutral blend (this occurs at 40% biodiesel, assuming linearity). The cetane enhancers di-tert-butyl peroxide (DTBP) and ethyl-hexyl nitrate (EHN) are both effective at reducing NO_x from biodiesel. The antioxidant TBHQ is also effective but NO_x reduction was small at the level tested and TBHQ may cause an increase in PM emissions. The idea of using antioxidants as NO_x reduction additives is clearly something that should be explored in more detail. Blending of 2% short chain fatty acid esters was not effective for reducing NO_x. The A1 additive obtained from Bioclean Fuels was effective at NO_x reduction but caused an unacceptably large increase in PM. Based on these results, use of the additives DTBP and EHN is the most practical approach at the present time. Using DTBP at 1 volume percent produces an incremental cost increase of $0.16 per gallon. For EHN at 0.5 volume percent the incremental cost increase per gallon is $0.05.

A nominally 10% aromatic fuel was used as a reference point to determine if B20 blends (blends of either biodiesel with certification diesel or 10% aromatic diesel) might have emissions levels allowing CARB certification. The 10% aromatic fuel met the requirements for sale of diesel fuel in California based on composition, it was not a CARB reference diesel. All of the B20 blends exhibited PM emissions below those for the CARB diesel. Fuels based on certification diesel did not in any case produce NO_x emissions equal to or below those of the 10% aromatic fuel. Even B20 fuels treated with DTBP have NO_x emissions that significantly exceed those of the 10% aromatic diesel. For B20 blends based on the 10% aromatic fuel, adding DTBP is effective at reducing NO_x to the base fuel level. Thus blending biodiesel with a California compliant diesel and treating with DTBP may be a route to a CARB certifiable B20.

Degree of unsaturation appears to be the key difference between soy and yellow grease (YG) based biodiesels from the standpoint of emissions performance. The iodine numbers of these fuels were 127 and 79, respectively. The cetane number of the YG fuel was correspondingly higher. For the B20 blends a significant (about 2%) NO_x increase relative to certification diesel was observed for soy but no significant increase was observed for YG. Treatment with 1% DTBP lowered NO_x by about the same amount for both blends. For B100 fuels, the PM emissions are approximately the same but YG (Bio3000) exhibits NO_x emissions that are lower, relative to soy diesel, by nearly 0.4 g/bhp-h. Treatment of B100 fuels with DTBP is effective at reducing NO_x, but not in proportion to the NO_x reduction observed for B20 blends. The facts that the NO_x reduction for DTBP is the same independent of biodiesel source, and decreases with increasing biodiesel content of the fuel seem important. These results may suggest that DTBP acts largely to lower the NO_x produced by burning the petroleum diesel fuel.

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INTRODUCTION

Biodiesel is an oxygenated diesel fuel made from vegetable oils and animal fats by converting the tri-glyceride fats to esters via various esterification processes. A number of studies have shown substantial particulate matter (PM) reductions for biodiesel and biodiesel blended with petroleum diesel (1) relative to petroleum diesel. However, most studies also show a significant increase in nitrogen oxides (NO_x) emissions (1). The cause of this increase in NO_x and solutions to this problem have been the subject of a considerable body of research under the DOE Biodiesel Program at the National Renewable Energy Laboratory (NREL).

In a previous study for NREL (2,3), we examined biodiesels produced from a variety of real-world feedstocks as well as technical grade fatty acid methyl and ethyl esters. Emissions performance in a heavy-duty truck engine using the U.S. heavy-duty federal test procedure (transient test) was measured. The objective was to understand the impact of biodiesel chemical structure, specifically fatty acid chain length and number of double bonds, on emissions of NO_x and PM. It was found that the molecular structure of biodiesel could have a substantial impact on emissions. For neat biodiesels (B100), PM emissions were essentially constant at about 0.07 g/bhp-h as long as density was less than 0.89 g/cm^3 or cetane number was greater than about 45. NO_x emissions increased with increasing fuel density or decreasing fuel cetane number. Increasing the number of double bonds, quantified as iodine number, correlated with increasing emissions of NO_x. The properties of density, cetane number, and iodine number were highly correlated with one another. This result cannot be explained by the well-known NO_x/PM tradeoff because PM remained constant but NO_x changed with fuel properties. Thus the increase in NO_x emissions observed for some biodiesels and for blends of biodiesel in petroleum diesel is not driven by thermal NO formation. The study additionally found that for fully saturated fatty acid chains NO_x emissions were lower than those for petroleum diesel. NO_x increased with decreasing fatty acid chain length for tests using fuels with 18, 16, and 12 carbon chains. Biodiesel composed of technical grade C12 saturated carbon chains (methyl laurate) was NO_x equivalent to certification diesel. Also, there was no significant difference in NO_x or PM emissions for the methyl and ethyl esters of identical fatty acids.

The results of the previous study suggest a number of approaches to reduce NO_x emissions by modifying biodiesel properties. These might be implemented through chemical modification of the fatty acid chain or through plant breeding to develop oils with more suitable properties. In the present study, we have examined a number of potential fuel additive and fuel blending solutions to the NO_x problem. These include blending with Fischer-Tropsch diesel and low aromatic diesel, as well as using several fuel additives. The goal of the study was to identify an approach for reducing the NO_x emissions of soy-based biodiesel by 4% for a B20 blend. The additives tested include the cetane improvers di-tert-butyl-peroxide (DTBP) and 2-ethyl-hexyl-nitrate (EHN), short chain fatty acid esters, tert-butyl-hydroquinone (TBHQ, a food antioxidant), and a proprietary additive called A1 provided by BioClean Fuels. Tests were conducted with biodiesels produced from both soy and yellow grease. There were significant differences between the two biodiesel-fuels with respect to degree of saturation, cetane number, iodine number, and fuel density. Base fuels were certification diesel and a California compliant 10% aromatic diesel.

METHODS

Fuels and Test Matrix

The fuels examined in this study are listed in Table 1. A 14-task statement of work defined the study design. The fuel testing tasks are outlined below.

Table 1. Fuels utilized in this study.

Fuel	Lot Number	Source
Certification diesel	0KP05202	Phillips Specialty Chemical
10% Aromatic diesel	0LP10A01	Phillips Specialty Chemical
Kerosene (No. 1 diesel)	Not provided	Colorado Petroleum Company
Fischer-Tropsch diesel	Not provided	Shell Oil Company (via NREL)
Soy methyl ester	B4-136	AG Environmental Products (Soygold)
Yellow grease methyl ester	Not provided	Griffin Industries (Bio3000)

Task 1. Fuel Quality Testing:

The base fuels listed in Table 1 were obtained and submitted for analysis to insure that minimum standards were met. The specific standards were ASTM PS121 for the biodiesel fuels, ASTM D975 for the certification diesel, and CARB standards for the 10% aromatic fuel.

Task 2. Baseline Regulated Emissions Tests:

Each of the fuels listed in Table 1 was tested in the DDC Series 60 engine for emissions performance. Tests included one cold start and a minimum of three hot starts for all fuels except the 10% aromatic for which only three hot starts were conducted.

Task 3. Testing Fischer-Tropsch/Biodiesel Blends:

Pure Fischer-Tropsch and blends of 80% FT/20% Soy and 80% Soy/20% FT were tested. Samples of FT diesel containing 1%, 3%, and 5% soy were submitted for lubricity analysis. The sample having the lowest soy diesel level that met the Engine Manufacturers Association recommended maximum High Frequency Reciprocating Rig (HFRR) wear scar maximum of 450 microns was also tested in the engine.

Task 4. Effectiveness of DTBP Additive in Soy B20:

A B20 prepared from soy and certification diesel was tested to demonstrate the NO_x increase typically observed. This fuel was then treated at 0.5, 1.0, and 1.5 volume percent DTBP and these fuels tested in the engine. The objective was to identify a DTBP blending level that reduced NO_x emissions by 4%. Earlier studies at Southwest Research Institute (SwRI) reported that EHN was not effective at reducing NO_x from soydiesel. Tests were also conducted to confirm this result.

Task 5. Effectiveness of DTBP in Other B20 Fuels:

The following B20 fuels were prepared and tested both with and without the DTBP additive at the treat rate determined in Task 4:

- Certification diesel/yellow grease

- 10% aromatic diesel/soy
- 10% aromatic diesel/yellow grease

Task 6. DTBP Effectiveness in Soy B100:
Neat soydiesel was tested using five times the DTBP treat rate determined for B20 in Task 4.

Task 7. DTBP Effectiveness in Yellow Grease B100:
Neat yellow grease biodiesel was tested using five times the DTBP treat rate determined for B20 in Task 4.

Task 8. Additive Testing for the U.S. Department of Agriculture (USDA), Peoria:
This task was not funded and therefore not performed.

Task 9. Additive Testing for USDA Philadelphia:
Dr. Michael Haas and Dr. Thomas Foglia of USDA Eastern Regional Research Center supplied Colorado School of Mines (CSM) with two fuel additives. These were a sample of short chain fatty acid methyl esters (USDA-1) and a food antioxidant, tert-butyl-hyroquinone (USDA-2). A B20 prepared from certification diesel and soy diesel was tested using these additives at treat rates recommended by Drs. Haas and Foglia.

Task 10. Bioclean Fuels A1 Additive:
Bioclean Fuels provided a proprietary additive called A1. A1 was tested in a B20 prepared from 10% aromatic fuel and soy diesel at a treat rate recommended by Bioclean Fuels.

Task 11. Bioclean Fuels A1 Additive-Further Tests:
The A1 additive was tested in a B20 prepared from certification diesel and soy diesel at a treat rate identical to that used in Task 10. A second test using soy B100 was planned. Upon direction from Dr. Shaine Tyson of NREL this second test was not performed.

Task 12. K50 Testing:
A blend of kerosene (No. 1 diesel) with 50% volume percent soydiesel and known as K50 was tested. Neat kerosene was also tested for comparison. K50 was then tested using 2.5 times the treat rate of the best NO_x reducing additive identified in previous tests with B20.

Task 13. Draft Report Preparation:
A draft final report is to be prepared and submitted to NREL as well as to several peer reviewers.

Task 14. Final Report:
Based on reviewers comments, the final report is to be revised and a final version submitted.

Fuel Property Measurement

Williams Laboratory in Kansas City, Missouri performed fuel property measurements with the following exceptions. Core Laboratory in Houston, Texas performed analysis of the FT diesel. Analysis of the soy and yellow grease biodiesels for fatty acid ester content was performed by the Eastern Regional Research Center of the USDA in Wyndmoor, Pennsylvania. Southwest

Research Institute of San Antonio, Texas conducted lubricity tests using the HFRR (high frequency reciprocating rig) test (ASTM-D6079 @ 60°C).

Emissions Testing

The system for emissions measurement for regulated pollutants (THC, CO, NO_X, and PM) includes supply of conditioned intake and dilution air, an exhaust dilution system, and capability for sampling of particulate and analysis of gaseous emissions. All components of the emissions measurement system meet the requirements for heavy-duty engine emissions certification testing as specified in Code of Federal Regulations Title 40, Part 86, Subpart N.

Test Engine:

The engine is a 1991 calibration Series 60 production model loaned by the Detroit Diesel Corporation. The six cylinder, four stroke engine is nominally rated at 345 bhp (257 kW) at 1800 rpm and is electronically controlled (DDEC-II), direct injected, turbocharged, and intercooled. Engine specifications are listed in Table 2. This is the engine model specified in California Code of Regulations Title 13 section 2282, subsection g for certification testing of diesel fuels.

Table 2. DDC Series 60 engine specifications and mapping parameters.

Serial Number	6R-544
Displacement	11.1 L
Rated Speed/Horsepower	1800 rpm/345 bhp
Max Torque Speed/Max Torque	1200 rpm/1335 ft-lb
Idle Speed/CITT	600 rpm/0 ft-lb
High Idle Speed	1940 rpm
Intake Depression	-16 ± 1 in H_2O
Backpressure	32.6 ± 3 in H_2O
Aftercooler Dp	40 ± 3 in H_2O
Intake Manifold Temperature	44±2°C

Regulated Gaseous Emissions Measurement:

All gas mass emissions are determined by background corrected flow compensated integration of the instantaneous mass rates. Tedlar bag samples of background air and exhaust sample are also collected. The exhaust sample is proportionally sampled through a critical flow orifice. The bag compositions are compared with the bag equivalent flow compensated emissions to validate the test runs. Agreement is always within 5% for the individual regulated gaseous emissions.

Particle Sampling for Mass:

Particulate matter is collected on Pallflex T60A20 70 mm filters of a common lot. Particulate matter is sampled through a secondary tunnel that insures a filtered gas temperature below 52°C (126°F). Two independent mass flow controllers are used to regulate the total filtered gas sample and the secondary dilution air rate. The computer determines the total sample volume by integrating the instantaneous flow difference. Flow is made proportional to the diluted exhaust by sending a varying secondary air flow set point from the test manager computer which is based upon the critical flow venturi (CFV) flow rate which in turn is a function of the diluted exhaust temperature at the venturi. The apparent sample flow rate depends on zero flow analog voltage outputs from the transmitters. These are logged before and after the test and the corrected integrated volume is established with a calibration model that considers the voltage offsets.

PM Background. Parallel background samples are not collected. Instead, the intake air is filtered to 95% ASHRAE efficiency and periodic background checks are made. Demineralized water is used for humidity control. The mass collected in the background check made during this program was extremely small. No background correction was made to the particulate determinations.

Weigh Room Conditions. Since the PM mass collected, especially for the biodiesel samples, was small even minor differences in filter weight due to water adsorption can impact the particulate mass emission. Particle filter handling and weighing is conducted in a yellow light, constant humidity weigh room held at 9±2°C (48±4°F) dew point, 50% nominal relative humidity, and 22±1°C (72±2°F).

Quality Control:
The testing is carried out in accordance with 40 CFR Part 86 Subpart N. In addition, a number of additional measures are taken to insure that the NO_x and PM emissions collected in this program are both precise and accurate.

Emission Gas Standards. Emission gases are 1% EPA Protocol Standards. Gas standards were not changed during this test program.

Carbon Balance. As a test quality-assurance check, a carbon balance is performed for each transient test. Diesel mass fuel consumption was monitored with a Micromotion DP-25 mass flow sensor and by weighing the fuel supply tank before and after a test using a load cell. Exhaust carbon is determined from the background corrected THC, CO, CO_2, and PM emissions data. The fuel analysis is used to estimate the H/C ratio of the THC. PM is assumed to be 100% carbon. Runs where carbon balance closure was more than +/-6% in error were generally rejected.

NO_x Humidity Correction. Humidity has a large influence on NO_x emissions. Humidity is measured continuously in the conditioned air inlet by two independently calibrated methods: a dew point meter and a polymer membrane sensor. Furthermore, the intake air is controlled to a 53°F (11.7°C) nominal dew point to insure that the NO_x correction factor (40 CFR 1342-94(d)(8)(iii)) is very near one and essentially constant from test to test. The two humidity measurements do not produce NO_x correction factors that differ by more than 2%.

The Effect of Intake Manifold Temperature on NO_x Emissions. The engine is equipped with a water-cooled turbocharger intercooler. The supply temperature and flow rate of cooling water to the intercooler are adjusted during the engine mapping process to match the manufacturer's design temperature for the intake air at rated speed and wide open throttle. The flow and inlet temperature are feedback controlled so that the temperature history of the manifold from test to test is repeatable. The maximum temperature and stage where it occurred are logged during each test to confirm that NO_x differences are not related to variations from test to test in the intake air temperature profile.

RESULTS

Base Fuel Properties

Base fuel properties and testing methods employed are listed in Table 3. Certification diesel has a cetane number of 47 and an aromatic content of 32%. The nominally 10% aromatic diesel has a cetane number of 48 and an aromatic content of 7.5%. Note that this fuel is not a CARB reference diesel nor is it a fuel certified as emissions equivalent to CARB reference diesel. As a fuel with less than 10% aromatic content it meets the requirements for sale in California based on composition. Comparison of biodiesels and biodiesel blends with this fuel is intended to provide an estimate of suitability of any of these fuels for possible CARB certification. FT diesel has an extremely high cetane number, as is typical for these fuels. While not measured, the aromatic content of FT diesel is zero. For the biodiesel fuels all of the property specifications of ASTM PS121 (shown in Appendix A) are met. Soygold has a cetane number of 47; a value regarded as typical for a soy-derived biodiesel (1). The cetane number of Bio3000 is 56. The kerosene or No. 1 diesel is at the light end of the No. 1 diesel range, and may even meet the specifications of a jet fuel.

The fatty acid makeup of the two biodiesels was also determined and these results are reported in Table 4. As expected, the yellow grease fuel contained significantly higher levels of saturated and monounsaturated compounds. The "other" column in Table 4 includes unidentified peaks in the chromatogram and less than 0.5% of the 20:0 methyl ester.

Certification Fuel Tests and Other Controls

The engine was initially mapped on certification diesel fuel and this map (run 5629) was used to generate the transient test for all testing on all fuels. A plot of the torque map is shown in Appendix B. All emissions testing data for this study are presented in Appendix C, in chronological order. Certification fuel runs were performed periodically throughout the test program to gauge engine drift. A single lot of certification diesel was used. The testing was performed in two campaigns. The first campaign occurred in January 2001 and the second campaign in March and early April 2001. Figure 1 shows daily average NO_x and PM emissions from the certification diesel runs. The two test campaigns are evident. A small (about 2%) difference in NO_x emissions on certification fuel was observed between the two campaigns. This most likely occurred because of repairs made to the NO_x analyzer during February, although drift of the engine itself cannot be ruled out. Certification fuel PM emissions are also slightly higher for the second campaign, although experimental variability is higher in the first campaign.

Tables 5 through 8 present descriptive statistics for the certification fuel runs in both campaigns. Within a given campaign the data are of high repeatability with 95% confidence interval for NO_x of better than ±1% and for PM of better than ±5%. A t-test comparing NO_x emissions for the two campaigns indicates that they are significantly different at better than 99% confidence ($p<0.0001$). PM emissions for the two campaigns are likely identical ($p=0.119$). In analyzing the data, runs will only be compared with certification fuel runs obtained during the same campaign.

Table 3. Results of fuel property testing for base fuels.

Property	Method	Units	Certification Diesel	10% Aromatic Diesel	FT Diesel	Soygold	Bio-3000	No. 1 Diesel
Cetane Number (CN)	ASTM-D613-86		47.4	48.2	>74.8	47.4	55.6	42.8
Cetane Index	ASTM-D975		48.3	49.4	78.3	--	--	45.8
Kinematic Viscosity 40C	ASTM-D445	mm2/s	2.7	2.5	3.34	4.066	4.735	1.3
Iodine Number	ASTM-D1959		--	--	--	127.4	78.8	--
Cloud Point	ASTM-D2500	F	3	-20	40	--	--	-61
Cloud Point	ASTM-D5773	C	--	--	--	-1	7	--
Flash Point	ASTM-D93	F	153	135	228	288	284	130
Cold Filter Plugging Point	ASTM-6371	C	--	--	0	-3	3	--
Pour Point	ASTM-D97	F	0	--	--	--	--	--
Total Sulfur by UVF	ASTM-D5453	wt%	--	--	--	0.000068	0.001468	--
Sulfur	ASTM-D2622	wt%	0.043	0.0057	--	--	--	0.0138
Ash Content	ASTM-D482	wt%	--	--	0.001	--	--	0.001
Sulfated Ash	ASTM-D874	wt%				0.003	0.01	--
Water Content	ASTM-D1796		--	--	<0.05	--	--	--
Specific Gravity	ASTM-D4052		0.8476	0.8302	--	--	--	----
Carbon Residue	ASTM-D189	wt%	--	--	<0.01	--	--	--
Carbon Residue	ASTM-D524	wt%	--	--	--	0.08	0.05	0.06
Corrosion, Copper strip	ASTM-D130		1A	1A	1A	1A	1A	--
Water and Sediment	ASTM-D2709	vol%	--	--	--	<0.005	<0.05	<0.05
Acid Number	ASTM-D664	mgKOH/g	--	--	--	0.03	0.37	--
Hydrocarbon Type:	ASTM-D1319							
Aromatics		%vol	31.9	7.5	--	--	--	--
Olefins		%vol	1.5	2.1	--	--	--	--
Saturates		%vol	66.6	90.4	--	--	--	--
Free Glycerin	ASTM	wt%				0.004	0.016	
Total Glycerin	D6584	wt%				0.184	0.038	
Distillation	ASTM-D86							
IBP		F	352	355	454	--	--	338
10		F	423	421	500	--	--	365
50		F	514	478	556	--	--	407
90		F	599	599	618	--	--	471
EP		F	642	658	638	--	--	515

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Table 4. Results of GC-MS analysis of biodiesel samples for specific species.

Fuel	C12:0	C14:0	C16:0	C16:1	C18:0	C18:1	C18:2	C18:3	Other
MW	214.351	242.405	270.459	268.443	298.513	296.497	296.497	294.481	
Unsaturations	0	0	0	1	0	1	2	3	
Soygold	0	0	11.96	0	3.88	22.63	54.52	6.6	0.41
Bio3000	0	0.93	23.30	1.28	9.73	49.65	15.11	0	0

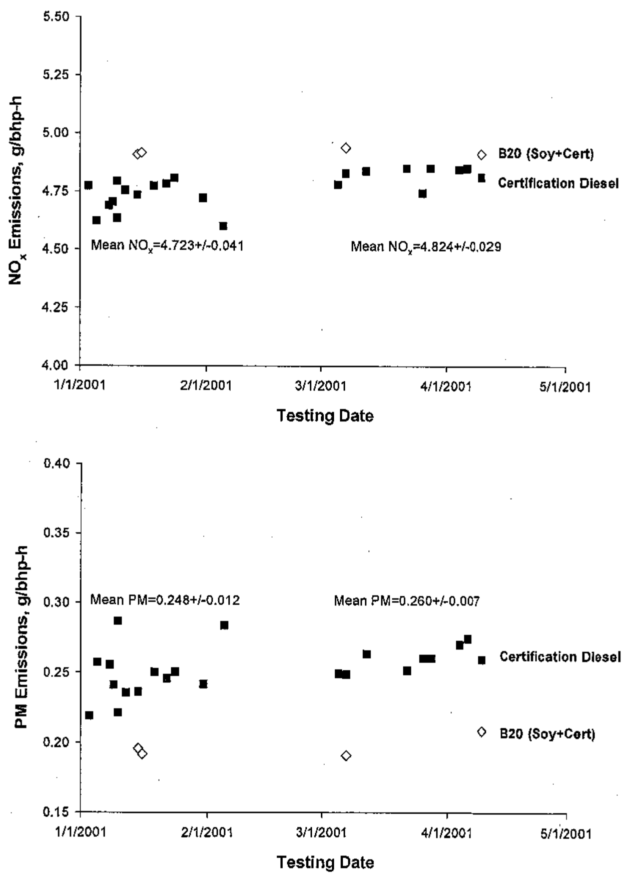

Figure 1. NO_x and PM emissions results for certification fuel runs performed over the study. All data points represent the average of three or more hot start runs.

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Also shown in Figure 1 are emissions results for a B20 prepared from soydiesel and certification diesel. These runs serve as an additional control. In all cases B20 NO_x emissions are between 2% and 3% higher than average certification fuel NO_x. B20 PM emissions are always at least 20% lower than certification fuel PM. Analysis of the fuel additive testing data will be based on a comparison of emissions with average B20 runs performed during the same campaign.

Table 5. Descriptive statistics for daily average NO_x emissions from the 1991 DDC Series 60 engine using EPA certification diesel, January campaign.

Mean	4.7228
Standard Error	0.0189
Median	4.7339
Standard Deviation	0.0683
Range	0.206
Minimum	4.6017
Maximum	4.8073
95% Confidence Interval	0.0413
Count	15

Table 7. Descriptive statistics for daily average NO_x emissions from the 1991 DDC Series 60 engine using EPA certification diesel, March campaign.

Mean	4.8241
Standard Error	0.0125
Median	4.8407
Standard Deviation	0.0374
Range	0.1067
Minimum	4.7458
Maximum	4.8525
95% Confidence Interval	0.0288
Count	11

Table 6. Descriptive statistics for daily average PM emissions from a 1991 DDC Series 60 engine using EPA certification diesel, Januray campaign.

Mean	0.2482
Standard Error	5.589e-3
Median	0.2460
Standard Deviation	0.0202
Range	0.0676
Minimum	0.2192
Maximum	0.2868
95% Confidence Interval	0.0122
Count	15

Table 8. Descriptive statistics for daily average PM emissions from a 1991 DDC Series 60 engine using EPA certification diesel, March campaign.

Mean	0.2599
Standard Error	2.981e-3
Median	0.2603
Standard Deviation	8.941e-3
Range	0.0258
Minimum	0.2488
Maximum	0.2746
95% Confidence Interval	0.0069
Count	11

Base Fuel Emissions

The base fuels for this study were tested for emissions in replicate transient tests. Results are reported in Table 9. A lubricity additive called Paradyne 655 was added to the FT diesel at 200 ppm to protect the engine during testing of this fuel. FT diesel is shown to provide significant emissions reductions relative to certification diesel and 10% aromatic diesel. Both soy-based biodiesel (Soygold) and yellow grease-based biodiesel (Bio3000) show a significant NO_x increase relative to certification fuel, as well as the PM decrease typical of these fuels. The kerosene or No. 1 diesel exhibited NO_x emissions similar to the 10% aromatic fuel but had significantly lower PM. Importantly, the coefficient of variation for NO_x measurements was always below 1%.

Table 9. Emissions testing results for base fuels[1].

Fuel		THC	NO_x	CO	CO_2	PM
		g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h
Cert Lot # 0KP05202	**Composite**	0.020	4.847	4.865	578	0.232
January 3, 2001	**Average Hot**	**0.020**	**4.773**	**4.604**	**574**	**0.233**
	Coefficient of Variation	16.7%	0.4%	1.0%	0.2%	1.8%
Campaign 1	**Average Hot**	**0.020**	**4.723**	**5.029**	**574**	**0.248**
Campaign 2	**Average Hot**	**0.020**	**4.824**	**5.110**	**571**	**0.260**
Shell FT/Paradyne	**Composite**	0.008	4.093	4.036	551	0.176
	Average Hot	**0.007**	**4.026**	**3.843**	**548**	**0.167**
	Coefficient of Variation	73.8%	0.2%	4.4%	0.2%	4.6%
Soygold	**Composite**	0.014	5.449	3.155	580	0.072
	Average Hot	**0.012**	**5.366**	**2.973**	**576**	**0.068**
	Coefficient of Variation	10.8%	0.2%	2.5%	0.2%	5.5%
Bio3000	**Composite**	0.006	5.065	3.289	580	0.083
	Average Hot	**0.004**	**4.981**	**3.105**	**576**	**0.078**
	Coefficient of Variation	71.0%	0.7%	4.3%	0.5%	8.4%
10%Aro Lot#0LP10A01	**Average Hot**	**0.029**	**4.478**	**4.980**	**569**	**0.231**
	Coefficient of Variation	24.0%	0.2%	3.1%	0.2%	2.8%
Kerosene	**Average Hot**	**0.086**	**4.527**	**4.005**	**554**	**0.199**
	Coefficient of Variation	5.1%	0.3%	1.7%	0.1%	2.4%

[1]Composite is the weighted average (1/7 cold+6/7hot average) and include a minimum of 3 hot start runs. Hot average is for 3 or more hot start runs.

Results for FT Diesel/Soy Diesel Blends

The objective of Task 3 of this project was to quantify the regulated emissions from different blends of biodiesel with Fischer-Tropsch (FT) diesel in compression ignition engines. Based on previous correlations between fuel density and NO_X, blending of a low-density diesel fuel with biodiesel was hypothesized to provide a NO_X reduction. Because Fischer Tropsch diesel also has high cetane and no aromatics, the impact of changing density could not be isolated, but it could be examined. Biodiesel has excellent lubricity properties, while FT diesel has poor lubricity. The combination of the two low-sulfur diesel fuels might provide a very low emission alternative fuel with excellent lubricity properties.

Fuel property testing results for neat FT diesel, biodiesel (Soygold), and certification fuel as well as the different biodiesel-FT blends are presented in Table 10. After blending to 20% soy in FT, the cetane number still exceeds 75. Blending 20% FT into soy increases cetane number to 53.3 and using a linear model suggests a blending cetane number for FT diesel of 77. If this were correct, the 20% soy in FT blend would have a calculated cetane number of 71. Cetane number measurements above about CN=65 are notoriously inaccurate and within this limitation the results are reasonably consistent. Blending soydiesel with FT diesel acts to depress cloud point and cold filter plugging point by a few degrees. Table 11 present HFRR lubricity data for several blends of biodiesel and FT diesel. The Engine Manufacturers Association recommends a maximum HFRR wear scar of 450 microns. A previous report indicates that the Shell FT diesel produces HFRR wear scar of more than 500 microns and that addition of 200 ppm of the

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Paradyne 655 lubricity additive reduces this to 210 (4). The average value for 1% biodiesel in FT is 300 micron (or 0.300 mm), well below the manufacturers recommended limit. Based on direction from Mr. Keith Vertin at NREL, a 1% biodiesel/FT diesel blend was selected for testing, along with the FT/B20 and FT/B80 blends specified in our contract.

The emissions testing results for the different runs are presented in Table 12. The coefficients of variation for NO_x and PM measurements were always below 1% and 6% respectively. Emissions of FT diesel and FT diesel with 1% biodiesel are essentially identical, as expected. Adding 20% or larger amounts of biodiesel to FT results in a significant increase in NO_x emissions and decrease in PM emissions. Note, however, that for FT/B20 the NO_x emission is still 0.5 g/bhp-h below the certification diesel level. There is a linear relation for both NO_x and PM emissions as a function of volume percent FT diesel, as shown in Figure 2. The regression equations shown in the figure indicate that a blend of 46% FT with soydiesel would have the same NO_x emissions as certification diesel.

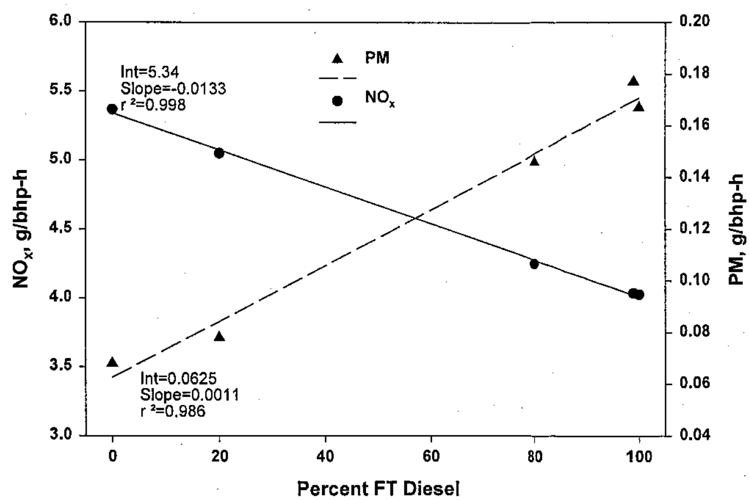

Figure 2. PM and NO_x emissions for blends of FT diesel in soydiesel.

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Table 10. Fuel property testing results for FT/Soydiesel blends.

Property	Method	Units	Cert fuel	F-T	Soygold	80%FT/20%SG	20%FT/80%SG
Cetane Number	ASTM-D613-86		47.4	>74.8	47.4	>74.8	53.3
Cetane Index	ASTM-D975		48.3	78.3	N/A	70.5	52.2
Kinematic Viscosity at 40 C	ASTM-D445	mm2/s	2.7	3.34	4.066	3.346	3.822
Iodine Number	ASTM-D1959				127.4	29	97.4
Cloud Point	ASTM-D2500	F	3	40		35	31
Cloud Point	ASTM-D5773	C			-1		
Cold Filter Plugging Point	ASTM-6371	C		0	-3	-3	-4
Pour Point	ASTM-D97	F	0				
Flash Point	ASTM-D93	F	153	228	288	219	227
Total Sulfur by UVF	ASTM-D5453	wt%			0.000068		
Sulfur	ASTM-D2622	wt%	0.043			0.0014	0.0024
Ash Content	ASTM-D482	wt%		0.001		0	0
Sulfated Ash	ASTM-D874	wt%			0.003		
Water Content	ASTM-D1796			<0.05			
Specific Gravity	ASTM-D4052		0.8476				
API Gravity	ASTM-D1298					44.6	32.9
Carbon Residue	ASTM-D189	wt%		<0.01			
Carbon Residue Ramsbottom	ASTM-D524	%			0.08	0.03	0.06
Corrosion, Copper strip	ASTM-D130		1A	1A	1A	1A	1A
Water and Sediment	ASTM-D2709	vol%			<0.005	26.6	0
Acid Number	ASTM-D664	mgKOH/g			0.03		
Hydrocarbon Type:	ASTM-D1319	%vol					
Aromatics	ASTM-D1319	%vol	31.9				
Olefins	ASTM-D1319	%vol	1.5				
Saturates	ASTM-D1319	%vol	66.6				
Distillation	ASTM-D86	F					
IBP	ASTM-D86	F	352	454		418	446
10	ASTM-D86	F	423	500		500	570
50	ASTM-D86	F	514	556		576	625
90	ASTM-D86	F	599	618		628	638
EP	ASTM-D86	F	642	638		636	638

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Table 11. Lubricity test results (HFRR).

Sample	Major Axis [mm]	Minor Axis [mm]	Wear Scar Diameter [mm]
80% Biodiesel in FT	0.16	0.10	0.130
80% Biodiesel in FT	0.17	0.10	0.135
80% Biodiesel in FT	0.17	0.10	0.135
Average			*0.133*
20% Biodiesel in FT	0.17	0.12	0.145
20% Biodiesel in FT	0.19	0.10	0.145
20% Biodiesel in FT	0.19	0.10	0.145
Average			*0.145*
5% Biodiesel in FT	0.21	0.15	0.180
5% Biodiesel in FT	0.21	0.12	0.165
5% Biodiesel in FT	0.21	0.15	0.180
Average			*0.175*
3% Biodiesel in FT	0.22	0.17	0.195
3% Biodiesel in FT	0.22	0.16	0.190
3% Biodiesel in FT	0.23	0.15	0.190
Average			*0.192*
1% Biodiesel in FT	0.32	0.26	0.290
1% Biodiesel in FT	0.33	0.27	0.300
1% Biodiesel in FT	0.35	0.27	0.310
Average			*0.300*

Table 12. Emissions testing results for soy diesel/FT diesel blends. Reported results are the average of at least three hot start runs.

Fuel		THC	NO_x	CO	CO_2	PM
		g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h
Shell FT w/Paradyne	**Average Hot**	**0.007**	**4.026**	**3.843**	**548**	**0.167**
	Coefficient of Variation	73.82%	0.21%	4.41%	0.24%	4.64%
99%FT/1%Soygold	**Average Hot**	**0.004**	**4.035**	**3.915**	**550**	**0.177**
	Coefficient of Variation	96.75%	0.27%	2.52%	0.53%	3.64%
80%FT/20%Soygold	**Average Hot**	**0.005**	**4.249**	**3.608**	**554**	**0.146**
	Coefficient of Variation	83.47%	0.40%	3.49%	0.29%	5.68%
20%FT/80%Soygold	**Average Hot**	**0.006**	**5.048**	**2.986**	**571**	**0.078**
	Coefficient of Variation	10.17%	0.37%	3.02%	0.33%	5.40%

Results for DTBP Treated Fuels

The objective of Task 4 of this project was to quantify the effects of di-tert-butyl peroxide (DTBP) on regulated emissions from B-20 biodiesel (soy) blends. Tasks 5, 6, and 7 examined DTBP in other B20 blends as well as in the neat biodiesel samples. Previous testing using DTBP by Southwest Research Institute, showed that 0.5% and 1.0% volume DTBP treat rates reduced NO_x emissions by approximately 1.1% and 5.2% compared to untreated B20 respectively (5,6). Unfortunately in neither case were the data useful in determining an effective DTBP treat rate to make the B20 NO_x neutral, since the untreated B20 blend had lower NO_x emissions than the baseline No. 2 diesel fuel.

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A baseline of 6 hot starts for B20 soy biodiesel in certification fuel was initially established. Using only the certification fuel runs acquired immediately before and after acquisition of the B20 baseline, which averaged 4.754 g/bhp-h, the NO_x increase is 3.3%. We prepared a series of B20 fuels (certification diesel + soydiesel) containing 0.5, 1.0, and 1.5 volume percent DTBP. Hot transient emissions summary results are presented in Table 13. The coefficients of variation for NO_x and PM measurements were always below 1% and 6% respectively. DTBP was effective at reducing NO_x at all three treatment-levels (all statistically significant at 95% confidence or greater). Figure 3 shows an approximately linear relationship between DTBP treat rate and NO_x emissions.

Percent NO_x reduction (with respect to untreated B20) versus percent volume DTBP is shown in Figure 4 and exhibits an approximately linear relationship (p-value for slope=0.02). Based on the linear regression equation shown in Figure 4, an approximate 4% reduction should be achieved using 1% volume DTBP. The 95% confidence interval on the slope of the regression in Figure 4 ranges from –6.23 to –1.42, thus the estimate of 1% volume DTBP is not very precise.

Table 13. Emissions summary for treatment of B20 (soy+cert) with DTBP, results are averages for three or more hot start runs.

Fuel		THC	NO_x	CO	CO_2	PM
		g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h
Certification Fuel	**Average Hot**	**0.016**	**4.734**	**5.049**	**574**	**0.236**
January 15, 2001	Coefficient of Variation	29.96%	0.18%	2.43%	0.0	1.32%
B20 Soy in CERT fuel	**Average Hot**	**0.013**	**4.912**	**4.677**	**576**	**0.194**
	Coefficient of Variation	76.55%	0.05%	3.38%	0.12%	4.00%
Certification Fuel	**Average Hot**	**0.012**	**4.774**	**5.005**	**576**	**0.250**
January 18, 2001	Coefficient of Variation	32.09%	0.57%	1.62%	0.0	1.34%
B20 Soy in CERT fuel	**Average Hot**	**0.005**	**4.792**	**4.414**	**574**	**0.197**
w/ 0.5% volume DTBP	Coefficient of Variation	74.64%	0.25%	3.05%	0.22%	1.68%
B20 Soy in CERT fuel	**Average Hot**	**0.016**	**4.754**	**4.436**	**575**	**0.210**
w/ 1.0 % volume DTBP	Coefficient of Variation	11.32%	0.15%	1.01%	0.24%	2.32%
B20 Soy in CERT fuel	**Average Hot**	**0.008**	**4.612**	**4.218**	**571**	**0.196**
w/ 1.5% volume DTBP	Coefficient of Variation	83.58%	0.09%	1.82%	0.29%	2.78%

Because DTBP was successful at reducing NO_x from a B20 composed of soy biodiesel and certification diesel, additional tests were conducted on its effects on NO_x emissions from the following B20 blends:

Soy in 10% aromatic fuel
Yellow grease in certification fuel
Yellow grease in 10% aromatic fuel

Emissions summary results are presented in Table 14, along with some earlier results. The coefficients of variation for NO_x and PM measurements were always below 1% and 4% respectively. DTBP was effective at reducing NO_x emissions to the base fuel level or below (by 3% to 4%) in all cases (significant at 95% confidence or greater).

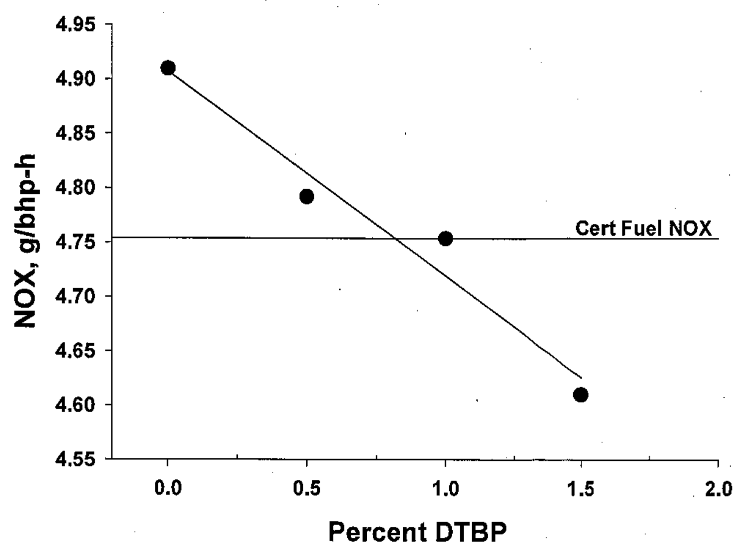

Figure 3. Relationship between DTBP blending level and NO_x emissions in B20 (soy+cert).

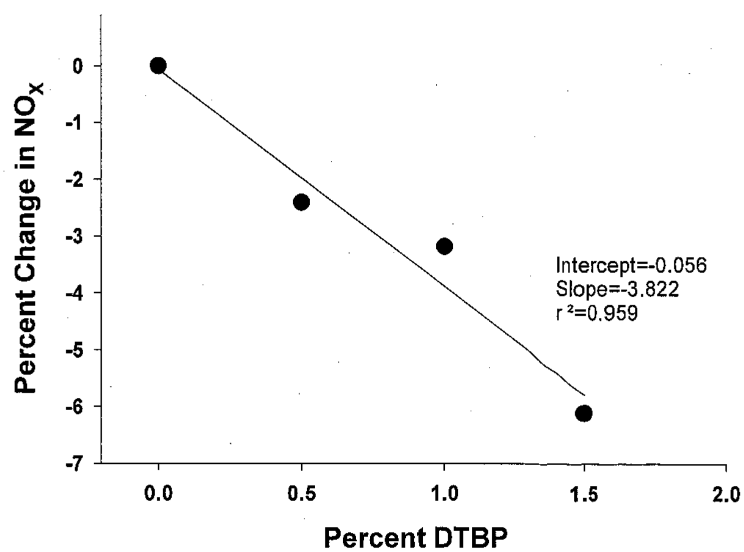

Figure 4. Effect of DTBP blending level on percent NO_x reduction for B20 (soy+cert).

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Fuel property testing results for all of these B20 fuels are shown in Table 15. Adding 1% DTBP to B20 (Soy+Cert) increased cetane number from 48 to 60. The results in Table 15 indicate an even larger cetane boost for B20 (Soy+10%) diesel, from 48 to 67, although a cetane number of 67 seems unreasonably high. However, *cetane number for the yellow grease based B20 fuels did not increase significantly*, even though a NO_x reduction was observed. This observation was confirmed by retesting two of the yellow grease containing fuels. Williams Laboratory claims that the same person measures all cetane numbers. This result may imply that DTBP does not reduce NO_x by increasing cetane number but by some other chemical effect.

A 5% DTBP blending level was used for testing B100. Testing results are shown in Table 16, along with other results for completeness. Certification fuel NO_x emissions averaged 4.82 g/bhp-h during Campaign 2 when these tests were conducted. Soy B100 increases NO_x to 5.45 g/bhp-h. Adding DTBP results in a decrease to 5.18 g/bhp-h. This result represents a statistically significant NO_x reduction, but it is still well above the certification fuel level. For yellow grease B100 (Bio3000) NO_x is 5.07 g/bhp-h and adding 5% DTBP reduces NO_x to 4.88 g/bhp-h. Again this NO_x reduction is statistically significant, and has reduced NO_x to the certification fuel level (emissions for the two fuels are the same with 97% confidence).

Table 14. Emissions summary for treatment of various B20 fuels with DTBP (1%), results are averages for three or more hot start runs.

Fuel		THC	NO_x	CO	CO_2	PM
		g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h
Certification Fuel	**Average Hot**	**0.02**	**4.723**	**5.011**	**573**	**0.248**
	Coefficient of Variation	0.35%	1.03%	0.20%	1.93%	8.62%
B20 (soy+cert)	**Average Hot**	**0.013**	**4.912**	**4.677**	**576**	**0.194**
	Coefficient of Variation	76.55%	0.05%	3.38%	0.12%	4.00%
B20 (soy+cert)	**Average Hot**	**0.016**	**4.754**	**4.436**	**575**	**0.210**
1.0 % volume DTBP	Coefficient of Variation	11.32%	0.15%	1.01%	0.24%	2.32%
B20 (YG+cert)	**Average Hot**	**0.009**	**4.780**	**4.658**	**577**	**0.208**
	Coefficient of Variation	22.83%	0.19%	2.34%	0.0	2.67%
B20 (YG+cert)	**Average Hot**	**0.009**	**4.637**	**4.498**	**574**	**0.208**
1.0 % volume DTBP	Coefficient of Variation	75.98%	0.14%	4.23%	0.0	2.75%
10% Aromatic	**Average Hot**	**0.029**	**4.478**	**4.980**	**569**	**0.231**
	Coefficient of Variation	0.240	0.002	0.031	0.002	0.028
B20 (Soy+10%)	**Average Hot**	**0.022**	**4.606**	**4.333**	**567**	**0.189**
	Coefficient of Variation	13.68%	0.09%	4.07%	0.0	4.08%
B20 (Soy+10%)	**Average Hot**	**0.016**	**4.469**	**4.445**	**569**	**0.201**
1.0 % volume DTBP	Coefficient of Variation	24.00%	0.20%	2.13%	0.0	1.68%
B20 (YG+10%)	**Average Hot**	**0.017**	**4.586**	**4.427**	**568**	**0.191**
	Coefficient of Variation	17.21%	0.29%	1.61%	0.0	2.51%
B20 (YG+10%)	**Average Hot**	**0.016**	**4.414**	**4.590**	**566**	**0.203**
1.0 % volume DTBP	Coefficient of Variation	17.22%	0.24%	1.50%	0.0	0.37%

Table 15. Fuel property testing results for B20 blends.

Property	Method	Units	B20 Soy/ CERT	B20 Soy/CERT+1 % DTBP	B20 Soy/10% Aromatic	B20 Soy/10% Aromatic+1% DTBP	B20 YG/CERT	B20 YG/CERT+ 1%DTBP	B20 YG/10% Aromatic	B20 YG/10%Aromatic+ 1% DTBP
Cetane Number (replicate)	ASTM-D613-86		47.7	60	48	67.4	44.7 (46.2)	45.1 (49.2)	47.7	48.2
Cetane Index	ASTM-D976		49.5		50.1		50.2	50.1	50.7	50.9
Specific Gravity	ASTM-D4052			0.852	0.8403	0.8383	0.852	0.8514	0.8388	0.8378
Flash Point	ASTM-D93	F	165		163	147.2	163	150	163	149
Kinematic Viscosity(at 100F)	ASTM-D445	mm2/s	2.88		2.702	5.054	2.918	2.855	2.782	2.744
Corrosion, Copper strip	ASTM-D130		1A		1A	1A	1A	1A	1A	1A
Ash Content	ASTM-D482	wt%	0.001		0	0.001	0.04	0.006	0	0
Carbon Residue Ramsbottom	ASTM-D524	% carbon	0.07		0.04	0.17	0.04	0.43	0.49	0.03
Cloud Point	ASTM-D2500	F	10		-2	-2.2	14	16	18	8
Sulfur	ASTM-D2622	wt%	0.0263		0.0027	0.0037	0.0268	0.0258	0.0035	0.0022
Water and Sediment	ASTM-D2709	vol%	0		<0.05	0.01	<0.05	<0.05	<.05	<.05
API Gravity	ASTM-D1298 /D287				36.8		34.5	34.6	37.1	37.3
Distillation	ASTM-D86	F								
IBP	ASTM-D86	F	365		388	169	375	175	396	176
10	ASTM-D86	F	437		431	433	446	440	432	435
50	ASTM-D86	F	542		511	510	548	545	511	510
90	ASTM-D86	F	631		640	649	632	635	641	647
FBP	ASTM-D86	F	654		658	656	659	652	659	656

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Table 16. Emission testing results for B100 fuels with and without DTBP, results are an average of 3 or more hot runs.

Fuel		THC	NO_x	CO	CO_2	PM
		g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h
Cert Fuel	**Average Hot**	**0.020**	**4.824**	**4.604**	**574**	**0.260**
Campaign 2 Avg	Coefficient of Variation	16.7%	0.4%	1.0%	0.2%	1.8%
Soygold	**Average Hot**	**0.012**	**5.366**	**2.973**	**576**	**0.068**
	Coefficient of Variation	10.8%	0.2%	2.5%	0.2%	5.5%
Soygold+5% DTBP	**Average Hot**	**0.027**	**5.184**	**2.470**	**556**	**0.064**
	Coefficient of Variation	7.73%	0.61%	3.21%	0.06%	6.08%
Bio3000	**Average Hot**	**0.004**	**4.981**	**3.105**	**576.**	**0.078**
	Coefficient of Variation	71%	0.7%	4.3%	0.5%	8.4%
Bio3000+5% DTBP	**Average Hot**	**0.016**	**4.881**	**2.861**	**556**	**0.078**
	Coefficient of Variation	12.43%	0.39%	5.22%	0.04%	6.54%

Results for EHN Treated B20 Blends

Studies conducted in 1994 at SwRI reported that EHN was not effective for NO_x reduction when added to soy-based biodiesel (5,6). However, the biodiesel available at that time was likely of low quality (high methanol, glycerol, and glyceride content) and it would be interesting to repeat those tests using a fuel meeting the requirements of ASTM PS121. Tests were conducted using 0.5% and 1.0% by volume EHN in B20 (soy+cert) and the results are shown in Table 17. Table 18 shows the results of statistical tests to quantify the significance of any differences observed. When comparing B20 to B20 with EHN (0.5%), it clear that the observed 2.3% NO_x reduction has a high degree of statistical significance. When comparing certification fuel emissions to B20+0.5% EHN is seems likely that EHN has reduced NO_x to the certification fuel level. A set of runs was also performed with 1.0% EHN and the NO_x in this case was statistically identical to that observed for 0.5%. Thus, our results do not replicate what was reported by SwRI however the SwRI study only tested EHN in a 2-stroke engine. In the present study with a 4-stroke engine both of the common cetane improvers, EHN and DTBP, reduced NO_x from soydiesel/certification diesel blends.

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Table 17. Emissions testing results for EHN in B20 (soy+cert fuel), results are average of three or more hot start runs.

Fuel		THC	NO_x	CO	CO_2	PM
		g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h
B20 (Soy+Cert)	**Average Hot**	**0.018**	**4.909**	**4.674**	**577**	**0.196**
January 15, 2001	Coefficient of Variation	6.95%	0.33%	3.28%	0.0	5.74%
B20 (Soy+Cert)	**Average Hot**	**0.007**	**4.916**	**4.679**	**575**	**0.192**
January 17, 2001	Coefficient of Variation	76.55%	0.05%	3.38%	0.0	4.00%
Certification Diesel	**Average Hot**	**0.041**	**4.830**	**5.106**	**557**	**0.249**
March 7, 2001	Coefficient of Variation	15.02%	0.73%	3.71%	0.31%	2.26%
B20 (Soy+Cert)	**Average Hot**	**0.037**	**4.941**	**4.616**	**558**	**0.191**
March 7, 2001	Coefficient of Variation	18.23%	0.23%	1.36%	0.06%	1.11%
Certification Diesel	**Average Hot**	**0.053**	**4.841**	**5.113**	**554**	**0.264**
March 12, 2001	Coefficient of Variation	2.76%	0.17%	1.37%	0.16%	2.42%
B20 (Soy+Cert)+0.5% EHN	**Average Hot**	**0.024**	**4.834**	**4.529**	**558**	**0.212**
March 13, 2001	Coefficient of Variation	26.99%	0.39%	3.39%	0.11%	2.39%
B20 (Soy+Cert)+1.0% EHN	**Average Hot**	**0.033**	**4.804**	**4.431**	**559**	**0.206**
March 13, 2001	Coefficient of Variation	13.16%	0.56%	1.58%	0.11%	1.90%
Certification Diesel	**Average Hot**	**0.029**	**4.800**	**5.190**	**560**	**0.258**
March 14, 2001	Coefficient of Variation	6.83%	0.55%	2.03%	0.13%	4.00%
Certification Diesel	**Average Hot**	**0.025**	**4.813**	**5.144**	**558**	**0.252**
April 10, 2001	Coefficient of Variation	12.10%	0.18%	2.51%	0.12%	0.68%
B20 (Soy+Cert)	**Average Hot**	**0.023**	**4.913**	**4.784**	**558**	**0.201**
April 10, 2001	Coefficient of Variation	17.82%	0.61%	2.25%	0.12%	2.05%
B20 (Soy+Cert)+0.5% EHN	**Average Hot**	**0.018**	**4.766**	**4.662**	**557**	**0.220**
April 10, 2001	Coefficient of Variation	9.62%	0.74%	2.22%	0.21%	9.59%
B20 (Soy+Cert)	**Average Hot**	**0.018**	**4.877**	**4.714**	**558**	**0.193**
April 19, 2001	Coefficient of Variation	11.28%	0.18%	2.91%	0.18%	1.18%

Table 18. Results of t-test for significance of differences in emissions for EHN containing fuels (Excel t-test tool, two-sample assuming equal variaances).

	B20 NO_x	**B20+EHN NO_x**	**p-value**
Compare untreated B20 to B20+0.5%EHN	4.9113	4.8002	6.87E-07
	Cert NO_x	**B20+EHN NO_x**	**p-value**
Compare cert to B20+0.5% EHN	4.8257	4.8002	0.159907

Testing of USDA Philadelphia Additives

Dr. Michael Haas and Dr. Thomas Foglia of USDA supplied two fuel additives:

USDA-1: A fuel composed of 90% soy biodiesel and 10% short chain fatty acid esters. The USDA fuel was tested as a B20 blend, with the final fuel composed of 80% certification diesel, 2% short chain esters, and 18 % soy diesel. The composition of the short chain ester mixture was:

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Methyl butyrate	411 ml	(41.1 volume %)
Methyl caproate	265 ml	(26.5 volume %)
Methyl caprylate	92 ml	(9.2 volume %)
Methyl decanoate	233 ml	(23.3 volume %)

This mixture was selected because in our previous study (2) it was demonstrated that shorter chain, saturated esters had lower NO_x emissions than the long chain unsaturated esters that are dominant in soy diesel. This was true even though NO_x emissions increased for saturated esters when the chain length was shortened.

USDA-2: A fuel composed of 100% soy biodiesel and 1% tert-butyl-hydroquinone, a food antioxidant (also known as TBHQ). The fuel was tested as a B20 with certification diesel; the blended fuel contained 0.2 wt% TBHQ. This additive was selected because in our previous study (2) it was shown that the increase in NO_x is not driven by thermal or Zeldovich NO_x formation and therefore may involve some pre-combustion chemistry of hydrocarbon free radicals. An anti-oxidant might react with these free radicals preventing their participation in a NO_x forming sequence of reactions.

Emissions summary results for these two fuel blends are presented in Table 19, along with some additional results for completeness. The coefficients of variation for NO_x and PM measurements were always below 1.4% and 4% respectively. The statistical analysis of the results reported here utilizes only certification fuel runs and untreated B20 runs from March and early April, 2001.

USDA-1: Certification fuel runs performed before and after testing of this additive in B20 averaged 4.85 g/bhp-h. The NO_x emission for the USDA-1 fuel was 5.012. The average untreated B20 NO_x was 4.93. The 3% increase in NO_x observed for USDA-1 is statistically significant at 98% confidence (p=0.01608). PM emissions are unchanged relative to B20. Thus, USDA-1 was not effective for NO_x reduction. USDA-1 had no significant impact on PM emissions.

USDA-2. Certification fuel runs performed before and after testing this B20 averaged 4.840 g/bhp-h of NO_x. The NO_x emission for the USDA-2 fuel was 4.894 g/bhp-h, 0.044 g/bhp-h higher than the bracketing certification fuel mean which is significantly higher at 99% confidence. The USDA-2 NO_x is 0.035 g/bhp-h lower than the mean B20 NO_x of 4.93. This NO_x reduction is significant at 99.5% confidence (p=0.005532) but apparently the treat rate of 0.2wt% is not adequate to reduce NO_x to the certification fuel level. TBHQ also had a negative effect on PM, causing PM to increase by 9% relative to the average B20 PM emission for the second testing campaign (significant at 99% confidence). This level of PM is still significantly below the PM emission level of certification diesel. Additional testing of TBHQ and other antioxidants is clearly warranted.

Table 19. Emissions summary results for testing of USDA addtives in B20 (soy+cert), results are averages of three or more hot start runs.

Fuel		THC	NO_x	CO	CO_2	PM
		g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h
B20 Soy/Cert fuel	**Average Hot**	**0.037**	**4.941**	**4.616**	**558**	**0.191**
March 7, 2001	Coefficient of Variation	18.23%	0.23%	1.36%	0.06%	1.11%
Cert Fuel	**Average Hot**	**0.036**	**4.853**	**5.283**	**560**	**0.260**
March 28, 2001	Coefficient of Variation	3.36%	0.07%	3.53%	0.07%	1.39%
B20 (Soy)/USDA-1	**Average Hot**	**0.030**	**5.012**	**4.719**	**562**	**0.192**
March 28, 2001	Coefficient of Variation	8.23%	1.31%	2.30%	0.22%	2.16%
Cert Fuel	**Average Hot**	**0.034**	**4.847**	**5.102**	**559**	**0.238**
April 4, 2001	Coefficient of Variation	13.15%	0.04%	2.26%	0.24%	2.15%
B20 (Soy)/USDA-2	**Average Hot**	**0.028**	**4.894**	**4.846**	**560**	**0.214**
April 5, 2001	Coefficient of Variation	9.74%	0.26%	2.84%	0.18%	3.35%
Cert Fuel	**Average Hot**	**0.030**	**4.852**	**5.386**	**559**	**0.232**
April 6, 2001	Coefficient of Variation	11.31%	0.59%	4.09%	0.23%	3.16%
B20 Soy/Cert fuel	**Average Hot**	**0.023**	**4.913**	**4.784**	**558**	**0.201**
April 10, 2001	Coefficient of Variation	17.82%	0.61%	2.25%	0.12%	1.98%

Testing of Bioclean Fuels Additive

The objective of Task 10 of this project was to test a B20 produced from soy and 10% aromatic diesel and containing the A-1 additive from Bioclean Fuels. Task 11 was to perform similar tests on B20 produced from soy and certification diesel, and on B100 soy. Based on the testing results, the NREL technical monitor (Dr. Shaine Tyson) directed us not to perform the B100 test. This section presents emissions results for the two fuels tested with A-1.

The B20 fuels were prepared, as directed by Bioclean Fuels, to contain 1 part in 40 of the liquid A-1 additive. The emissions summary results are presented in Table 20 along with some results from other tasks for completeness. The coefficients of variation for NO_x and PM measurements were always below 1% and 4% respectively.

A-1 in CARB/B20: NO_x emissions from CARB diesel were 4.48 g/bhp-h and increased to 4.61 g/bhp-h upon addition of 20-volume percent soy diesel. Adding A-1 produced NO_x emissions of 4.56 g/bhp-h, which represents no change in NO_x emissions at the 99% confidence level. Adding A-1 caused PM to increase from 0.189 to 0.237 g/bhp-h; essentially eliminating any PM benefit from the biodiesel.

A-1 in Cert/B20: NO_x emissions for certification diesel ran about 4.85 g/bhp-h during late March and early April. Adding 20% soy diesel increased this to 4.91 g/bhp-h. Adding A-1 produced a NO_x emission of 4.84 g/bhp-h, indicating that A-1 successfully reduced NO_x by about 2% for this fuel. However, PM emissions were about 0.23 g/bhp-h. This is identical to PM emissions from certification diesel on bracketing runs and significantly higher than the 0.201 g/bhp-h measured for B20 shortly thereafter. This indicates that A-1 eliminates the PM benefit of using biodiesel.

Table 20. Emissions summary for testing of Bioclean Fuels additive A-1; results are an average of three or more hot start runs.

Fuel		THC	NO_x	CO	CO_2	PM
		g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h
10% Aromatic	**Average Hot**	**0.029**	**4.478**	**4.980**	**569**	**0.231**
January 12, 2001	Coefficient of Variation	24.05%	0.17%	3.13%	0.0	2.84%
B20 Soy/10% Aro	**Average Hot**	**0.022**	**4.606**	**4.333**	**567**	**0.189**
January 23, 2001	Coefficient of Variation	13.68%	0.09%	4.07%	0.2%	4.08%
B20 Soy/Cert fuel	**Average Hot**	**0.037**	**4.941**	**4.616**	**558**	**0.191**
March 7, 2001	Coefficient of Variation	18.23%	0.23%	1.36%	0.06%	1.11%
Cert Fuel	**Average Hot**	**0.034**	**4.746**	**5.091**	**555**	**0.260**
March 26, 2001	Coefficient of Variation	16.63%	0.42%	2.23%	0.14%	1.40%
B20 Soy/10% Aro+A1	**Average Hot**	**0.040**	**4.563**	**4.949**	**554**	**0.237**
March 26, 2001	Coefficient of Variation	6.54%	0.10%	1.79%	0.26%	2.30%
Cert Fuel	**Average Hot**	**0.036**	**4.853**	**5.283**	**560**	**0.260**
March 28, 2001	Coefficient of Variation	3.36%	0.07%	3.53%	0.07%	1.39%
Cert Fuel	**Average Hot**	**0.034**	**4.847**	**5.102**	**559**	**0.238**
April 4, 2001	Coefficient of Variation	13.15%	0.04%	2.26%	0.24%	2.42%
B20 Soy/Cert+A1	**Average Hot**	**0.033**	**4.848**	**5.324**	**563**	**0.233**
April 4, 2001	Coefficient of Variation	12.34%	0.35%	0.75%	0.18%	1.08%
Cert Fuel	**Average Hot**	**0.030**	**4.852**	**5.386**	**559**	**0.232**
April 6, 2001	Coefficient of Variation	11.31%	0.59%	4.09%	0.23%	3.68%
B20 Soy/Cert fuel	**Average Hot**	**0.023**	**4.913**	**4.784**	**558**	**0.201**
April 10, 2001	Coefficient of Variation	17.82%	0.61%	2.25%	0.12%	2.05%
Cert Fuel	**Average Hot**	**0.025**	**4.813**	**5.144**	**558**	**0.252**
April 10, 2001	Coefficient of Variation	12.10%	0.18%	2.51%	0.12%	0.68%

Testing of K50

The objective of Task 12 of this project is to test a blend of No. 1 diesel (also known as kerosene) and 50 volume percent soy diesel (this blend is referred to as K50). The best NO_x reduction additive identified under this project is to then be blended with K50 and tested. The best NO_x reduction additive identified was di-tert-butyl-peroxide (DTBP). For B20 produced from soy diesel and certification diesel 0.93, volume percent DTBP was sufficient to reduce NO_x to the certification fuel level. For K50 we elected to employ 2.5 times as much DTBP (2.3%) because the fuel contains 2.5 times as much biodiesel. This is the most conservative way to insure that a NO_x reduction occurs. As the data will show, 2.3% DTBP is more than was needed to achieve NO_x neutrality with certification diesel. A better approach may have been to note that the desired percent NO_x reduction was 2.55%. For B20 this could be obtained with 0.624% DTBP suggesting that 2.5 times this level, or 1.456% DTBP, might have been adequate for the K50 fuel.

The kerosene was obtained locally. Emissions results for the kerosene without biodiesel were obtained for completeness. All emissions results are shown in Table 21. Kerosene produced a NO_x level of 4.53 g/bhp-h. Testing of 50% soy/50% kerosene produced a NO_x emission of 4.94 g/bhp-h, essentially the same level observed for B20 from certification diesel and 20% soy.

Addition of 2.3% DTBP reduced NO_x to 4.70 g/bhp-h. This is well below the certification fuel level of 4.85 g/bhp-h and suggests that between 1% and 1.5% DTBP would have been adequate. Fuel analysis results are reported in Table 22. Addition of 2.3% DTBP to K50 was very effective at increasing cetane number, causing an increase of 28 cetane units.

Table 21. Emissions summary for testing of kerosene/soydiesel blends; results are average of three or more hot starts.

Fuel		THC	NO_x	CO	CO_2	PM
		g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h	g/bhp-h
B20 Soy/Cert fuel	**Average Hot**	**0.037**	**4.941**	**4.616**	**558**	**0.191**
March 7, 2001	Coefficient of Variation	18.23%	0.23%	1.36%	0.06%	1.11%
Cert Fuel	**Average Hot**	**0.034**	**4.852**	**5.091**	**555**	**0.260**
March 22, 2001	Coefficient of Variation	16.63%	0.42%	2.23%	0.14%	1.40%
Kerosene	**Average Hot**	**0.086**	**4.527**	**4.005**	**554**	**0.199**
March 27, 2001	Coefficient of Variation	5.06%	0.27%	1.66%	0.09%	2.41%
K50	**Average Hot**	**0.046**	**4.940**	**3.611**	**556**	**0.115**
March 28, 2001	Coefficient of Variation	6.03%	1.06%	3.51%	0.24%	3.47%
Cert Fuel	**Average Hot**	**0.036**	**4.853**	**5.283**	**560**	**0.260**
March 28, 2001	Coefficient of Variation	3.36%	0.07%	3.53%	0.07%	1.39%
Cert Fuel	**Average Hot**	**0.030**	**4.852**	**5.386**	**559**	**0.232**
April 6, 2001	Coefficient of Variation	11.31%	0.59%	4.09%	0.23%	3.68%
K50+2.3%DTBP	**Average Hot**	**0.029**	**4.701**	**3.252**	**556**	**0.084**
April 6, 2001	Coefficient of Variation	2.41%	0.69%	3.84%	0.09%	8.56%

Table 22. Fuel property testing results for kerosene and K50 fuels.

Property	Method	Units	No. 1 Diesel	Soygold	K50	K50+2.3%DTBP
Cetane Number (CN)	ASTM-D613-86		42.8	47.4	44.3	72.2
Cetane Index	ASTM-D975		45.8	--	51.2	48.7
Kinematic Viscosity 40C	ASTM-D445	mm2/s	1.3	4.066	2.2	2.2
Iodine Number	ASTM-D1959		--	127.4	--	--
Cloud Point	ASTM-D2500	F	-61	--	17	16
Cloud Point	ASTM-D5773	C	--	-1	--	--
Flash Point	ASTM-D93	F	130	288	144	126
Cold Filter Plugging Point	ASTM-6371	C	--	-3	--	--
Pour Point	ASTM-D97	F	--	--	--	--
Total Sulfur by UVF	ASTM-D5453	wt%	--	0.000068	--	--
Sulfur	ASTM-D2622	wt%	0.0138	--	0.0062	0.0071
Ash Content	ASTM-D482	wt%	0.001	--	--	--
Sulfated Ash	ASTM-D874	wt%	--	0.003	--	--
Water Content	ASTM-D1796		--	--	--	--
Specific Gravity	ASTM-D4052		--	--	--	--
Carbon Residue	ASTM-D189	wt%	--	--	--	--
Carbon Residue	ASTM-D524	wt%	0.06	0.08	0.01	0.06
Corrosion, Copper strip	ASTM-D130		--	1A		
Water and Sediment	ASTM-D2709	vol%	<0.05	<0.005	<0.05	<0.05
Acid Number	ASTM-D664	mgKOH/g	--	0.03	--	--
Hydrocarbon Type:	ASTM-D1319					
Aromatics		%vol	--	--	--	--
Olefins		%vol	--	--	--	--
Saturates		%vol	--	--	--	--
Free Glycerin	ASTM D6584	wt%		0.004		
Total Glycerin		wt%		0.184		
Distillation	ASTM-D86					
IBP		F	338	--	347	251
10		F	365	--	381	380
50		F	407	--	522	518
90		F	471	--	644	648
EP		F	515	--	651	648

DISCUSSION

Effect of Various NO_x Reduction Strategies

This study has examined a number of approaches for NO_x reduction from biodiesel. These are compared in Table 23 for B20 (soy+cert). Blending FT diesel at very high percentages can produce a NO_x neutral fuel. Lowering the base fuel aromatic content from 31.9 to 7.5% (nominally 10% aromatic fuel) was very successful at lowering NO_x. If all other factors are equal and if the effect of aromatic content is linear, using a base fuel having 25.8% aromatics should provide a NO_x neutral B20. The results also suggest that using kerosene as the base fuel could lead to a NO_x neutral blend (this occurs at 40% biodiesel, assuming linearity). The cetane enhancers DTBP and EHN are both effective at reducing NO_x from biodiesel. The antioxidant TBHQ is also effective, but may cause an increase in PM emissions. The idea of using antioxidants as NO_x reduction additives is clearly something that should be explored in more detail. It may be that other antioxidants also reduce NO_x but have no negative impact on PM emissions. The Bioclean Fuels A1 additive is effective at NO_x reduction but causes an unacceptably large increase in PM.

Table 23. Effect of various fuel additives on NO_x reduction for B20 (soy+cert).

Additive	NO_x, g/bhp-h	% Reduction‡	Significance (p-value)
Certification Diesel	4.85	--	--
B20 (soy+cert) no additive	4.93	--	--
46% FT diesel	4.85	1.62	Predicted*
10% Aromatic base stock	4.61	6.49	<0.001
1% DTBP	4.75	3.65	0.030
0.5% EHN	4.83	2.03	<0.001
2% Short Chain FA Esters (USDA-1)	5.01	-1.62	<0.001
0.2% TBHQ (USDA-2)	4.89	0.08$^+$	0.001
2.5% A1	4.85	1.62$^+$	0.018

‡Relative to B20 (soy+cert)
*Predicted from model shown in Figure 2
$^+$These additives also caused an increase in PM

Use of Cetane Improvers for Biodiesel NO_x Reduction

Perhaps the most practical strategy for NO_x reduction in the short term is the use of cetane improvers. This is because altering the base fuel properties may severely limit the marketability of biodiesel, and the other additives caused an increase in PM or had no effect. A recently obtained quotation (7) indicates that DTBP can be obtained in truckload quantities for $2.45 per lb. Assuming B20 has a density of 7.1 lb/gal, and DTBP has a density of 6.59lb/gal, 1 volume percent is 0.066 lb of DTBP. This translates into an incremental cost of $0.162 per gallon. For EHN the density is 8.0 lb/gal and 0.04 lb is required to make 0.5 volume percent. EHN has recently been quoted on the internet spot market for $1.25/lb or an incremental cost per gallon of $0.05. Biodiesel is currently selling at between $1 and $1.70 per gallon (8) while petroleum diesel sells for an average of $1.42 per gallon in 49 states and $1.55 per gallon in California (9).

California diesel fuel averages approximately 16% aromatic content (10) and, as discussed above, using a base fuel with less than 25.8% aromatic content should result in B20 NO_x emissions below those for certification diesel. So using a low aromatic California diesel as the blending diesel to lower NO_x relative to certification diesel, if such a fuel was available, would have an incremental cost on the order of $0.13 per gallon.. FT diesel sells for $0.20 to $0.50 more than California diesel so blending high levels of FT with biodiesel to reduce NO_x may not be an economically viable alternative.

Comparisons with 10% Aromatic Diesel

For a diesel fuel to be legal for sale in California it must meet EPA's requirements, and in addition it must be proven to be emissions equivalent to a 10% aromatic CARB reference diesel or have less than 10% aromatic content (California Code of Regulations Title 13 section 2282, subsection g). In this study we tested a nominally 10% aromatic fuel as a reference point for gauging the potential of B20 blends for possible CARB certification. Results for several B20 blends are shown in Figure 5 and compared to emissions from the 10% aromatic fuel. All of the B20 blends exhibited PM emissions below those measured for the 10% aromatic diesel. However, B20 fuels based on certification diesel did not in any case exhibit NO_x emissions at or below the emissions of the 10% aromatic fuel. B20 blends produced from the 10% aromatic fuel and including DTBP were NO_x equivalent or better. Thus blending of biodiesel with a California compliant diesel and treating it with DTBP may be a route to a CARB certifiable B20.

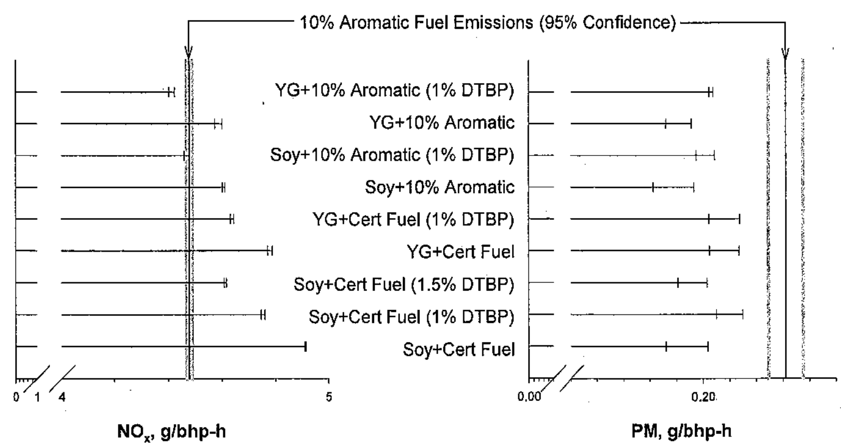

Figure 5. Comparison of B20 emissions with emissions for 10% aromatic diesel.

Comparison of Soy and YG Biodiesels

Degree of unsaturation appears to be the key difference between soy and yellow grease (YG) based biodiesels from the standpoint of emissions performance (2,3). The iodine numbers of

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these fuels were 127 and 79, respectively. The cetane number of the YG fuel was correspondingly higher. Figure 6 compares emissions for various fuels containing soy and YG biodiesel. For B100 fuels, the PM emissions are approximately the same, but YG (Bio3000) exhibited NO_x emissions that were lower by nearly 0.4 g/bhp-h. Treating B100 fuels with DTBP was effective at reducing NO_x, but not in proportion to the NO_x reduction observed for B20 blends.

For the B20 blends a significant (about 2%) NO_x increase relative to certification diesel was observed for soy but no significant increase was observed for YG. Treatment with 1% DTBP lowered NO_x by about the same amount for both blends. The fact that the NO_x reduction for DTBP is the same independent of biodiesel source, and that it decreases with increasing biodiesel content of the fuel may suggest that DTBP acts largely to lower the NO_x produced by burning the petroleum diesel fuel. The fact that DTBP can reduce NO_x emissions from petroleum diesel is well documented (11).

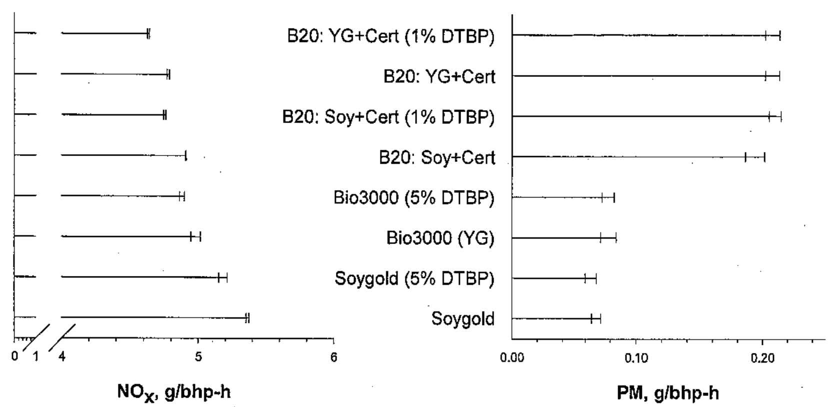

Figure 6. Comparison of emissions for various soy and yellow grease biodiesel fuels.

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CONCLUSIONS

This study has examined a number of approaches for NO_x reduction from biodiesel. The following conclusions can be drawn:

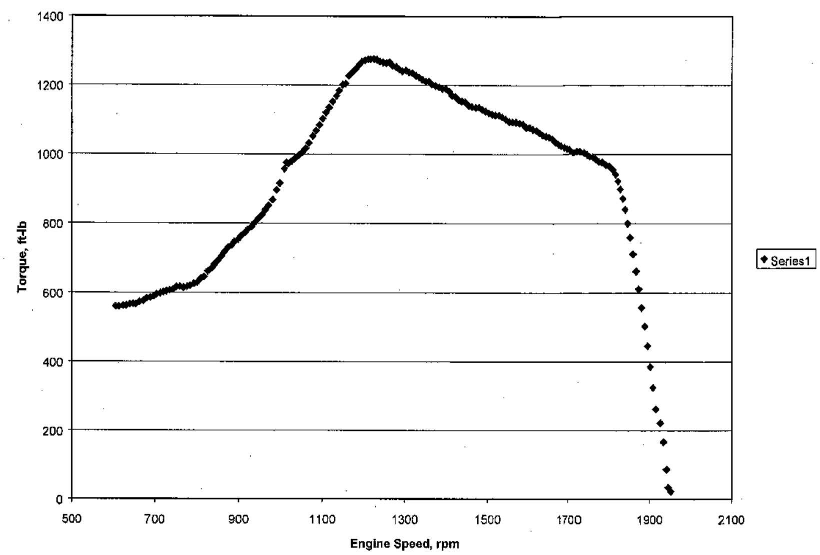
- The cetane improvers DTBP and EHN are effective for reducing NO_x by 4% in B20 blends. DTBP at 1.0 volume percent will add on the order of $0.16 per gallon and EHN at 0.5 volume percent will add on the order of $0.05 per gallon to the cost of biodiesel.
- DTBP is also effective at NO_x reduction for B100 fuels but not in proportion to the NO_x reduction observed for B20 blends. This may indicate that cetane improvers act largely to lower the NO_x produced during burning of the petroleum diesel fuel.
- Blending with a low aromatic diesel, kerosene, or FT diesel is also effective at reducing NO_x.
- The antioxidant TBHQ significantly reduced NO_x but also caused a small increase in PM. The use of antioxidants in general is worthy of further study.
- Short chain fatty acid esters were not effective for NO_x reduction.
- Bioclean Fuels A1 additive is effective at NO_x reduction but also produces a significant increase in PM.
- No combination of biodiesel with certification fuel and fuel additives produced NO_x emissions levels below that observed for a 10% aromatic fuel, suggesting that CARB certification using a 30% aromatic base fuel is not possible. Lowering aromatic content to roughly 25% and addition of cetane improver would be necessary for NO_x neutrality relative to 10% aromatic fuel.

APPENDIX A: ASTM PS121 SPECIFICATION FOR BIODIESEL FUELS

Property		ASTM Method	Limits	Units
Flash Point		93	100 min	°C
Water and Sediment		2709	0.05 max	Vol %
Carbon Residue		4530	0.05 max	Wt %
	or	524	0.09 max	Wt%
Sulfated Ash		874	0.02 max	Wt %
Kinematic Viscosity@40°C		445	1.9-6.0	mm^2/sec
Sulfur		5453	0.05 max	Wt %
Cetane Number		613	40 min	
Cloud Point		2500	Report	°C
Copper Strip Corrosion		130	No. 3 max	
Acid number		664	0.80 max	Mg KOH/gm
Free Glycerine		GC[1]	0.02 max	Wt %
Total Glycerine		GC[1]	0.24 max	Wt %

APPENDIX B: ENGINE TORQUE MAP

The chart below shows the engine map, acquired on certification diesel fuel, that was used to generate the transient cycle for all transient runs in this test program (the map is run number 5629).



APPENDIX C: EMISSIONS DATA

FUEL	Run #	Date		bhp-h	THC g/bhp-h	NOx g/bhp-h	CO g/bhp-h	CO2 g/bhp-h	PM g/bhp-h
Cert Lot # 0KP05202	5746	1/3/01	C	21.791	0.025	5.285	6.430	605.0	0.218
Cert Lot # 0KP05202	5747	1/3/01	H	21.791	0.016	4.769	4.553	575.3	0.214
Cert Lot # 0KP05202	5748	1/3/01	H	21.819	0.023	4.759	4.646	573.2	0.221
Cert Lot # 0KP05202	5749	1/3/01	H	21.836	0.020	4.792	4.612	573.5	0.222
Composite					**0.020**	**4.847**	**4.865**	**578.5**	**0.219**
Hot Average				**21.815**	**0.020**	**4.773**	**4.604**	**574.0**	**0.219**
Coefficient of Variation				**0.10%**	**16.70%**	**0.35%**	**1.03%**	**0.0**	**1.93%**
Shell FT w/ Paradyne 655	5751	1/4/01	C	21.599	0.018	4.491	5.196	573.8	0.231
Shell FT w/ Paradyne 655	5752	1/4/01	H	21.632	0.012	4.033	4.021	549.5	0.174
Shell FT w/ Paradyne 655	5753	1/4/01	H	21.571	0.003	4.017	3.823	547.2	0.169
Shell FT w/ Paradyne 655	5754	1/4/01	H	21.542	0.005	4.029	3.684	547.4	0.159
Composite					**0.008**	**4.093**	**4.036**	**551.7**	**0.176**
Hot Average				**21.582**	**0.007**	**4.026**	**3.843**	**548.1**	**0.167**
Coefficient of Variation				**0.21%**	**73.82%**	**0.21%**	**4.41%**	**0.0**	**4.64%**
Cert Lot # 0KP05202	5755	1/5/01	H	21.814	0.011	4.581	5.077	570.8	0.268
Cert Lot # 0KP05202	5756	1/5/01	H	21.767	0.018	4.635	4.762	571.7	0.248
Cert Lot # 0KP05202	5757	1/5/01	H	21.816	0.018	4.651	5.043	571.8	0.256
Hot Average		1/5/01		**21.799**	**0.015**	**4.622**	**4.961**	**571.4**	**0.257**
Coefficient of Variation				**0.13%**	**25.98%**	**0.79%**	**3.49%**	**0.0**	**3.87%**
80%FT/20%Soygold	5758	1/5/01	H	21.546	0.010	4.268	3.751	556.0	0.155
80%FT/20%Soygold	5759	1/5/01	H	21.492	0.001	4.238	3.557	552.9	0.146
80%FT/20%Soygold	5760	1/5/01	H	21.483	0.004	4.239	3.515	553.6	0.138
Hot Average				**21.507**	**0.005**	**4.249**	**3.608**	**554.2**	**0.146**
Coefficient of Variation				**0.16%**	**83.47%**	**0.40%**	**3.49%**	**0.0**	**5.68%**
Cert Lot # 0KP05202	5761	1/8/01	H	21.752	0.018	4.682	5.208	574.7	0.259
Cert Lot # 0KP05202	5762	1/8/01	H	21.791	0.025	4.696	4.974	573.4	0.252
Hot Average		1/8/01		**21.771**	**0.021**	**4.689**	**5.091**	**574.0**	**0.255**
Coefficient of Variation				**0.13%**	**21.63%**	**0.21%**	**3.25%**	**0.0**	**1.84%**
20%FT/80%Soygold	5763	1/8/01	H	21.419	0.006	5.069	3.089	572.5	0.082
20%FT/80%Soygold	5764	1/8/01	H	21.424	0.007	5.043	2.925	569.3	0.077
20%FT/80%Soygold	5765	1/8/01	H	21.439	0.006	5.033	2.943	572.6	0.074
Hot Average				**21.427**	**0.006**	**5.048**	**2.986**	**571.5**	**0.078**
Coefficient of Variation				**0.05%**	**10.17%**	**0.37%**	**3.02%**	**0.0**	**5.40%**
Cert Lot # 0KP05202	5766	1/9/01	H	21.758	0.014	4.695	5.135	575.4	0.234
Cert Lot # 0KP05202	5767	1/9/01	H	21.797	0.020	4.715	5.211	575.1	0.248
Hot Average		1/9/01		**21.778**	**0.017**	**4.705**	**5.173**	**575.3**	**0.241**
Coefficient of Variation				**0.13%**	**21.35%**	**0.30%**	**1.03%**	**0.0**	**4.01%**

FUEL	Run #	Date		bhp-h	THC g/bhp-h	NOx g/bhp-h	CO g/bhp-h	CO2 g/bhp-h	PM g/bhp-h
1% SoyGold in FT	5768	1/9/01	H	21.475	0.004	4.045	3.951	553.7	0.183
1% SoyGold in FT	5769	1/9/01	H	21.464	0.000	4.024	3.990	549.8	0.178
1% SoyGold in FT	5770	1/9/01	H	21.500	0.007	4.037	3.803	547.9	0.170
Hot Average				**21.480**	**0.004**	**4.035**	**3.915**	**550.5**	**0.177**
Coefficient of Variation				**0.09%**	**96.75%**	**0.27%**	**2.52%**	**0.0**	**3.64%**
Cert Lot # 0KP05202	5772	1/9/01	H	21.756	0.014	4.627	5.141	573.0	0.323
Cert Lot # 0KP05202	5773	1/9/01	H	21.695	0.017	4.643	4.939	573.5	0.251
Hot Average				**21.725**	**0.015**	**4.635**	**5.040**	**573.3**	**0.287**
Coefficient of Variation				**0.20%**	**13.99%**	**0.24%**	**2.84%**	**0.0**	**17.78%**
SoyGold	5774	1/10/01	C	21.374	0.024	5.946	4.245	605.7	0.097
SoyGold	5775	1/10/01	H	21.448	0.011	5.367	3.047	577.1	0.073
SoyGold	5776	1/10/01	H	21.391	0.012	5.353	2.899	576.2	0.067
SoyGold	5777	1/10/01	H	21.409	0.013	5.378	2.973	575.0	0.065
Composite					**0.014**	**5.449**	**3.155**	**580.3**	**0.072**
Hot Average				**21.416**	**0.012**	**5.366**	**2.973**	**576.1**	**0.068**
Coefficient of Variation				**0.14%**	**10.82%**	**0.23%**	**2.48%**	**0.0**	**5.46%**
Cert Lot # 0KP05202	5778	1/10/01	H	21.718	0.026	4.804	5.248	573.6	0.229
Cert Lot # 0KP05202	5779	1/10/01	H	21.674	0.018	4.785	4.809	576.3	0.213
Hot Average				**21.696**	**0.022**	**4.794**	**5.029**	**574.9**	**0.221**
Coefficient of Variation				**0.14%**	**27.11%**	**0.28%**	**6.17%**	**0.0**	**5.19%**
Bio3000	5780	1/11/01	C	21.466	0.020	5.570	4.390	602.7	0.112
Bio3000	5781	1/11/01	H	21.426	0.000	4.938	3.047	575.5	0.082
Bio3000	5785	1/11/01	H	21.395	0.004	5.007	3.289	579.6	0.080
Bio3000	5786	1/11/01	H	21.393	0.006	4.971	2.980	573.3	0.068
Bio3000	5787	1/11/01	H	21.394	0.007	5.008	3.106	576.7	0.078
Composite					**0.006**	**5.065**	**3.289**	**580.1**	**0.082**
Hot Average				**21.402**	**0.004**	**4.981**	**3.105**	**576.3**	**0.077**
Coefficient of Variation				**0.07%**	**70.98%**	**0.67%**	**4.28%**	**0.0**	**8.25%**
Cert Lot # 0KP05202	5788	1/12/01	H	21.710	0.019	4.742	5.022	576.6	0.225
Cert Lot # 0KP05202	5789	1/12/01	H	21.747	0.028	4.760	5.113	575.9	0.238
Cert Lot # 0KP05202	5790	1/12/01	H	21.723	0.025	4.760	4.982	574.4	0.244
Hot Average		1/12/01		**21.727**	**0.024**	**4.754**	**5.039**	**575.6**	**0.236**
Coefficient of Variation				**0.09%**	**19.75%**	**0.22%**	**1.32%**	**0.0**	**4.18%**
10% Aro Lot#0LP10A01	5793	1/12/01	H	21.630	0.035	4.474	5.155	570.5	0.238
10% Aro Lot#0LP10A01	5794	1/12/01	H	21.624	0.021	4.473	4.859	568.5	0.225
10% Aro Lot#0LP10A01	5795	1/12/01	H	21.605	0.029	4.486	4.924	569.9	0.229
Hot Average				**21.620**	**0.029**	**4.478**	**4.980**	**569.6**	**0.231**
Coefficient of Variation				**0.06%**	**24.05%**	**0.17%**	**3.13%**	**0.0**	**2.84%**

FUEL	Run #	Date		bhp-h	THC g/bhp-h	NOx g/bhp-h	CO g/bhp-h	CO2 g/bhp-h	PM g/bhp-h
Cert Lot # 0KP05202	5797	1/15/01	H	21.799	0.013	4.728	5.136	574.4	0.238
Cert Lot # 0KP05202	5798	1/15/01	H	21.814	0.020	4.740	4.962	573.7	0.234
Hot Average		1/15/01		**21.806**	**0.016**	**4.734**	**5.049**	**574.1**	**0.236**
Coefficient of Variation				**0.05%**	**29.96%**	**0.18%**	**2.43%**	**0.0**	**1.32%**
20% SoyGold in CERT Lot# 0KP05202	5799	1/15/01	H	21.744	0.019	4.899	4.759	577.6	0.196
20% SoyGold in CERT Lot# 0KP05202	5800	1/15/01	H	21.730	0.017	4.900	4.497	576.6	0.185
20% SoyGold in CERT Lot# 0KP05202	5802	1/15/01	H	21.754	0.019	4.928	4.766	579.3	0.208
Hot Average				**21.743**	**0.018**	**4.909**	**4.674**	**577.9**	**0.196**
Coefficient of Variation				**0.05%**	**6.95%**	**0.33%**	**3.28%**	**0.0**	**5.74%**
20% SoyGold in CERT Lot# 0KP05202	5807	1/17/01	H	21.730	0.002	4.919	4.862	576.1	0.201
20% SoyGold in CERT Lot# 0KP05202	5808	1/17/01	H	21.710	0.005	4.915	4.593	575.7	0.188
20% SoyGold in CERT Lot# 0KP05202	5809	1/17/01	H	21.734	0.012	4.915	4.583	574.8	0.188
Hot Average				**21.725**	**0.007**	**4.916**	**4.679**	**575.5**	**0.192**
Coefficient of Variation				**0.06%**	**76.55%**	**0.05%**	**3.38%**	**0.0**	**4.00%**
20% SoyGold in CERT Lot# 0KP05202 + 0.5%DTBP	5810	1/18/01	H	21.737	0.008	4.781	4.548	576.3	0.198
20% SoyGold in CERT Lot# 0KP05202 + 0.5%DTBP	5811	1/18/01	H	21.747	0.005	4.790	4.279	573.9	0.193
20% SoyGold in CERT Lot# 0KP05202 + 0.5%DTBP	5814	1/18/01	H	21.740	0.001	4.805	4.416	574.4	0.199
Hot Average				**21.741**	**0.005**	**4.792**	**4.414**	**574.9**	**0.197**
Coefficient of Variation				**0.02%**	**74.64%**	**0.25%**	**3.05%**	**0.0**	**1.68%**
Cert Lot # 0KP05202	5815	1/19/01	H	21.820	0.012	4.802	5.036	578.3	0.254
Cert Lot # 0KP05202	5816	1/19/01	H	21.828	0.008	4.748	5.067	576.3	0.251
Cert Lot # 0KP05202	5817	1/19/01	H	21.808	0.016	4.772	4.914	575.1	0.247
Hot Average		1/19/01		**21.819**	**0.012**	**4.774**	**5.005**	**576.5**	**0.250**
Coefficient of Variation				**0.05%**	**32.09%**	**0.57%**	**1.62%**	**0.0**	**1.34%**
20% SoyGold in CERT Lot# 0KP05202 + 1.0%DTBP	5818	1/19/01	H	21.746	0.019	4.758	4.429	576.5	0.205
20% SoyGold in CERT Lot# 0KP05202 + 1.0%DTBP	5820	1/19/01	H	21.778	0.015	4.746	4.485	573.7	0.210
20% SoyGold in CERT Lot# 0KP05202 + 1.0%DTBP	5821	1/19/01	H	21.763	0.016	4.760	4.396	575.3	0.215
Hot Average				**21.763**	**0.016**	**4.754**	**4.436**	**575.1**	**0.210**
Coefficient of Variation				**0.07%**	**11.32%**	**0.15%**	**1.01%**	**0.0**	**2.32%**
20% SoyGold in CERT Lot# 0KP05202 + 1.5%DTBP	5718	11/16/00	H	21.681	0.016	4.615	4.303	573.0	0.190
20% SoyGold in CERT Lot# 0KP05202 + 1.5%DTBP	5719	11/16/00	H	21.677	0.003	4.607	4.155	571.3	0.200
20% SoyGold in CERT Lot# 0KP05202 + 1.5%DTBP	5720	11/16/00	H	21.676	0.007	4.612	4.194	569.7	0.197
Hot Average				**21.678**	**0.008**	**4.612**	**4.218**	**571.3**	**0.196**
Coefficient of Variation				**0.01%**	**83.58%**	**0.09%**	**1.82%**	**0.0**	**2.78%**

FUEL	Run #	Date		bhp-h	THC g/bhp-h	NOx g/bhp-h	CO g/bhp-h	CO2 g/bhp-h	PM g/bhp-h
20% Bio-3000 in CERT Lot# 0KP05202	5822	1/22/01	H	21.772	0.007	4.770	4.783	577.1	0.213
20% Bio-3000 in CERT Lot# 0KP05202	5823	1/22/01	H	21.802	0.012	4.784	4.606	579.0	0.209
20% Bio-3000 in CERT Lot# 0KP05202	5824	1/22/01	H	21.762	0.009	4.786	4.584	574.8	0.202
Hot Average				**21.778**	**0.009**	**4.780**	**4.658**	**577.0**	**0.208**
Coefficient of Variation				**0.10%**	**22.83%**	**0.19%**	**2.34%**	**0.0**	**2.67%**

FUEL	Run #	Date		bhp-h	THC g/bhp-h	NOx g/bhp-h	CO g/bhp-h	CO2 g/bhp-h	PM g/bhp-h
Cert Lot # 0KP05202	5825	1/22/01	H	21.790	0.017	4.759	5.137	577.0	0.250
Cert Lot # 0KP05202	5826	1/22/01	H	21.815	0.018	4.785	4.908	575.8	0.244
Cert Lot # 0KP05202	5827	1/22/01	H	21.812	0.020	4.805	4.863	575.8	0.244
Hot Average		1/22/01		**21.806**	**0.018**	**4.783**	**4.969**	**576.2**	**0.246**
Coefficient of Variation				**0.06%**	**7.15%**	**0.48%**	**2.96%**	**0.0**	**1.37%**
20% Bio-3000 in CERT Lot# 0KP05202 + 1.0%DTBP	5828	1/23/01	H	21.775	0.012	4.630	4.701	576.6	0.211
20% Bio-3000 in CERT Lot# 0KP05202 + 1.0%DTBP	5829	1/23/01	H	21.796	0.001	4.637	4.470	573.2	0.211
20% Bio-3000 in CERT Lot# 0KP05202 + 1.0%DTBP	5830	1/23/01	H	21.774	0.013	4.643	4.324	572.6	0.201
Hot Average				**21.782**	**0.009**	**4.637**	**4.498**	**574.1**	**0.208**
Coefficient of Variation				**0.06%**	**75.98%**	**0.14%**	**4.23%**	**0.0**	**2.75%**
20% SoyGold in 10%AROMATIC lot # 0LP10A01	5831	1/23/01	H	21.719	0.019	4.610	4.491	568.3	0.195
20% SoyGold in 10%AROMATIC lot # 0LP10A01	5832	1/23/01	H	21.680	0.025	4.602	4.366	566.9	0.191
20% SoyGold in 10%AROMATIC lot # 0LP10A01	5833	1/23/01	H	21.695	0.023	4.607	4.143	566.1	0.180
Hot Average				**21.698**	**0.022**	**4.606**	**4.333**	**567.1**	**0.189**
Coefficient of Variation				**0.09%**	**13.68%**	**0.09%**	**4.07%**	**0.19%**	**4.08%**
Cert Lot # 0KP05202	5834	1/24/01	H	21.806	0.016	4.788	5.171	575.3	0.265
Cert Lot # 0KP05202	5835	1/24/01	H	21.834	0.022	4.809	4.804	573.9	0.248
Cert Lot # 0KP05202	5836	1/24/01	H	21.811	0.016	4.825	4.809	573.6	0.239
Hot Average		1/24/01		**21.817**	**0.018**	**4.807**	**4.928**	**574.2**	**0.251**
Coefficient of Variation				**0.07%**	**18.72%**	**0.38%**	**4.26%**	**0.0**	**5.37%**
20% Bio-3000 in 10%AROMATIC lot# 0LP10A01	5837	1/24/01	H	21.723	0.014	4.601	4.508	569.5	0.196
20% Bio-3000 in 10%AROMATIC lot# 0LP10A01	5838	1/24/01	H	21.732	0.019	4.579	4.399	568.2	0.188
20% Bio-3000 in 10%AROMATIC lot# 0LP10A01	5839	1/24/01	H	21.726	0.019	4.578	4.374	567.2	0.187
Hot Average				**21.727**	**0.017**	**4.586**	**4.427**	**568.3**	**0.191**
Coefficient of Variation				**0.02%**	**17.21%**	**0.29%**	**1.61%**	**0.0**	**2.51%**
20% Bio-3000 In 10%Aromatic Lot# 0LP10A01+1.0% DTBP	5840	1/25/01	H	21.652	0.015	4.427	4.659	568.1	0.203
20% Bio-3000 In 10%Aromatic Lot# 0LP10A01+1.0% DTBP	5841	1/25/01	H	21.651	0.019	4.406	4.590	567.4	0.204
20% Bio-3000 In 10%Aromatic Lot# 0LP10A01+1.0% DTBP	5842	1/25/01	H	21.636	0.014	4.410	4.521	565.0	0.204
Hot Average				**21.646**	**0.016**	**4.414**	**4.590**	**566.8**	**0.203**
Coefficient of Variation				**0.04%**	**17.22%**	**0.24%**	**1.50%**	**0.0**	**0.37%**
20% SoyGold in 10%Aromatic lot # 0LP10A01+1.0 %DTBP	5843	1/25/01	H	21.592	0.016	4.480	4.528	570.2	0.198
20% SoyGold in 10%Aromatic lot # 0LP10A01+1.0 %DTBP	5844	1/25/01	H	21.653	0.012	4.465	4.465	569.1	0.205
20% SoyGold in 10%Aromatic lot # 0LP10A01+1.0 %DTBP	5845	1/25/01	H	21.621	0.019	4.463	4.341	570.5	0.201
				21.622	**0.016**	**4.469**	**4.445**	**569.9**	**0.201**
				0.14%	**24.00%**	**0.20%**	**2.13%**	**0.0**	**1.68%**
Cert Lot # 0KP05202	5846	1/31/01	C	21.734	0.003	4.744	5.017	560.8	0.275
Cert Lot # 0KP05202	5847	1/31/01	H	21.766	0.010	4.707	4.766	560.5	0.254
Cert Lot # 0KP05202	5848	1/31/01	H	21.807	0.012	4.704	4.793	561.1	0.248
Cert Lot # 0KP05202	5849	1/31/01	H	21.808	0.013	4.758	4.811	562.4	0.224
Hot Average		1/31/01		**21.793**	**0.011**	**4.723**	**4.790**	**561.3**	**0.242**
Coefficient of Variation				**0.11%**	**12.47%**	**0.64%**	**0.48%**	**0.0**	**6.58%**

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FUEL	Run #	Date		bhp-h	THC g/bhp-h	NOx g/bhp-h	CO g/bhp-h	CO2 g/bhp-h	PM g/bhp-h
Cert Lot # 0KP05202	5879	2/15/01	C	21.810	0.018	5.015	5.850	578.3	0.305
Cert Lot # 0KP05202	5880	2/15/01	H	21.842	0.016	4.797	5.382	572.8	0.287
Cert Lot # 0KP05202	5881	2/15/01	H	21.827	0.020	4.832	5.584	574.9	0.305
Hot Average				**21.826**	**0.018**	**4.881**	**5.605**	**575.323**	**0.299**
Coefficient of Variation				**0.07%**	**10.71%**	**2.39%**	**4.19%**	**0.48%**	**3.47%**
Cert Lot # 0KP05202	5883	2/16/01	H	21.842	0.021	4.871	5.039	570.7	0.264
Cert Lot # 0KP05202	5884	2/16/01	H	21.871	0.018	4.902	5.144	571.1	0.266
Cert Lot # 0KP05202	5887	2/16/01	H	21.898	0.017	4.872	4.984	570.6	0.255
Hot Average				**21.870**	**0.018**	**4.882**	**5.056**	**570.802**	**0.262**
Coefficient of Variation				**0.13%**	**10.82%**	**0.36%**	**1.61%**	**0.04%**	**2.33%**
Cert Lot # 0KP05202	5923	3/7/01	H	21.933	0.039	4.869	5.283	557.7	0.252
Cert Lot # 0KP05202	5924	3/7/01	H	21.928	0.048	4.818	4.906	555.1	0.242
Cert Lot # 0KP05202	5925	3/7/01	H	21.927	0.036	4.802	5.129	558.3	0.252
Hot Average				**21.929**	**0.041**	**4.830**	**5.106**	**557.051**	**0.249**
Coefficient of Variation				**0.02%**	**15.02%**	**0.73%**	**3.71%**	**0.31%**	**2.26%**
20% SoyGold in CERT lot:OKPO5202	5926	3/7/01	H	21.815	0.029	4.947	4.687	558.4	0.194
20% SoyGold in CERT lot:OKPO5202	5927	3/7/01	H	21.839	0.040	4.949	4.589	558.9	0.189
20% SoyGold in CERT lot:OKPO5202	5928	3/7/01	H	21.865	0.042	4.928	4.571	559.1	0.191
Hot Average				**21.840**	**0.037**	**4.941**	**4.616**	**558.787**	**0.191**
Coefficient of Variation				**0.11%**	**18.23%**	**0.23%**	**1.36%**	**0.06%**	**1.11%**
Cert Lot # 0KP05202	5930	3/12/01	H	21.885	0.054	4.831	5.107	553.9	0.267
Cert Lot # 0KP05202	5931	3/12/01	H	21.911	0.051	4.844	5.047	554.8	0.256
Cert Lot # 0KP05202	5932	3/12/01	H	21.902	0.053	4.846	5.186	555.6	0.267
Hot Average				**21.900**	**0.053**	**4.841**	**5.113**	**554.770**	**0.264**
Coefficient of Variation				**0.06%**	**2.76%**	**0.17%**	**1.37%**	**0.16%**	**2.42%**
20:1 SoyGold + DTBP	5933	3/12/01	H	21.642	0.027	5.208	2.545	557.1	0.066
20:1 SoyGold + DTBP	5934	3/12/01	H	21.615	0.024	5.148	2.477	556.8	0.066
20:1 SoyGold + DTBP	5935	3/12/01	H	21.630	0.028	5.194	2.387	556.4	0.060
Hot Average				**21.629**	**0.027**	**5.184**	**2.470**	**556.796**	**0.064**
Coefficient of Variation				**0.06%**	**7.73%**	**0.61%**	**3.21%**	**0.06%**	**6.08%**
20% SoyGold + 0.5% EHN in Cert lot # OKPO5202	5936	3/13/01	H	21.841	0.017	4.855	4.672	558.6	0.218
20% SoyGold + 0.5% EHN in Cert lot # OKPO5202	5937	3/13/01	H	21.831	0.028	4.827	4.549	557.4	0.209
20% SoyGold + 0.5% EHN in Cert lot # OKPO5202	5938	3/13/01	H	21.810	0.028	4.820	4.367	558.1	0.209
Hot Average				**21.827**	**0.024**	**4.834**	**4.529**	**558.028**	**0.212**
Coefficient of Variation				**0.07%**	**26.99%**	**0.39%**	**3.39%**	**0.11%**	**2.39%**
20% SoyGold + 1.0% EHN in Cert lot # OKPO5202	5939	3/13/01	H	21.792	0.033	4.834	4.438	559.7	0.202
20% SoyGold + 1.0% EHN in Cert lot # OKPO5202	5940	3/13/01	H	21.868	0.029	4.794	4.498	559.0	0.210
20% SoyGold + 1.0% EHN in Cert lot # OKPO5202	5941	3/13/01	H	21.843	0.038	4.783	4.358	558.5	0.206
Hot Average				**21.834**	**0.033**	**4.804**	**4.431**	**559.085**	**0.206**
Coefficient of Variation				**0.18%**	**13.16%**	**0.56%**	**1.58%**	**0.11%**	**1.90%**

FUEL	Run #	Date		bhp-h	THC g/bhp-h	NOx g/bhp-h	CO g/bhp-h	CO2 g/bhp-h	PM g/bhp-h
20:1 Bio-3000 + DTBP	5942	3/14/01	H	21.430	0.018	4.901	3.033	556.4	0.083
20:1 Bio-3000 + DTBP	5943	3/14/01	H	21.444	0.015	4.863	2.773	556.0	0.079
20:1 Bio-3000 + DTBP	5944	3/14/01	H	21.451	0.014	4.879	2.776	556.3	0.073
Hot Average				**21.442**	**0.016**	**4.881**	**2.861**	**556.253**	**0.078**
Coefficient of Variation				**0.05%**	**12.43%**	**0.39%**	**5.22%**	**0.04%**	**6.54%**
Cert Lot # 0KP05202	5945	3/14/01	H	21.834	0.032	4.776	5.292	560.1	0.248
Cert Lot # 0KP05202	5946	3/14/01	H	21.855	0.028	4.795	5.082	561.1	0.256
Cert Lot # 0KP05202	5947	3/14/01	H	21.864	0.028	4.828	5.196	561.6	0.269
Hot Average				**21.851**	**0.029**	**4.800**	**5.190**	**560.947**	**0.258**
Coefficient of Variation				**0.07%**	**6.83%**	**0.55%**	**2.03%**	**0.13%**	**4.00%**
Cert Lot # 0KP05202	5952	3/22/01	C	21.902	0.032	4.866	5.388	556.2	0.271
Cert Lot # 0KP05202	5953	3/22/01	H	21.918	0.041	4.859	5.072	556.3	0.248
Cert Lot # 0KP05202	5954	3/22/01	H	21.884	0.036	4.855	5.104	555.4	0.245
Cert Lot # 0KP05202	5955	3/22/01	H	21.881	0.037	4.843	5.245	557.7	0.262
Hot Average				**21.894**	**0.038**	**4.852**	**5.140**	**556.460**	**0.252**
Coefficient of Variation				**0.09%**	**7.25%**	**0.17%**	**1.79%**	**0.20%**	**3.60%**
40:1 B-20Soy in 10%Aromatic / A-1	5965	3/26/01	H	21.731	0.037	4.558	5.051	555.7	0.234
40:1 B-20Soy in 10%Aromatic / A-1	5966	3/26/01	H	21.748	0.042	4.568	4.903	554.6	0.244
40:1 B-20Soy in 10%Aromatic / A-1	5967	3/26/01	H	21.750	0.042	4.564	4.893	552.9	0.234
Hot Average				**21.743**	**0.040**	**4.563**	**4.949**	**554.415**	**0.237**
Coefficient of Variation				**0.05%**	**6.54%**	**0.10%**	**1.79%**	**0.26%**	**2.30%**
Kerosene	5968	3/27/01	H	21.486	0.113	5.140	5.837	580.6	0.256
Kerosene	5969	3/27/01	H	21.420	0.082	4.521	4.069	555.3	0.204
Kerosene	5970	3/27/01	H	21.421	0.085	4.520	4.011	554.3	0.198
Kerosene	5971	3/27/01	H	21.401	0.091	4.542	3.937	555.1	0.194
Hot Average				**21.414**	**0.086**	**4.527**	**4.005**	**554.917**	**0.199**
Coefficient of Variation				**0.05%**	**5.06%**	**0.27%**	**1.66%**	**0.09%**	**2.41%**
K50 (50% Kerosene + 50% SoyGold)	5972	3/28/01	H	21.445	0.044	5.000	3.749	555.8	0.119
K50 (50% Kerosene + 50% SoyGold)	5973	3/28/01	H	21.483	0.045	4.915	3.500	557.5	0.112
K50 (50% Kerosene + 50% SoyGold)	5974	3/28/01	H	21.464	0.049	4.904	3.585	554.9	0.112
Hot Average				**21.464**	**0.046**	**4.940**	**3.611**	**556.070**	**0.115**
Coefficient of Variation				**0.09%**	**6.03%**	**1.06%**	**3.51%**	**0.24%**	**3.47%**
Cert Lot # 0KP05202	5976	3/28/01	H	21.775	0.035	4.850	5.151	560.5	0.258
Cert Lot # 0KP05202	5977	3/28/01	H	21.806	0.037	4.855	5.415	561.1	0.263
Hot Average				**21.791**	**0.036**	**4.853**	**5.283**	**560.763**	**0.260**
Coefficient of Variation				**0.10%**	**3.36%**	**0.07%**	**3.53%**	**0.07%**	**1.39%**
18% SoyGold in CERT lot: 0KP05202 + 2% USDA-1	5978	3/28/01	H	21.719	0.032	5.088	4.844	560.8	0.196
18% SoyGold in CERT lot: 0KP05202 + 2% USDA-1	5979	3/28/01	H	21.727	0.030	4.979	4.641	562.1	0.188
18% SoyGold in CERT lot: 0KP05202 + 2% USDA-1	5980	3/28/01	H	21.743	0.028	4.970	4.674	563.2	0.191
Hot Average				**21.730**	**0.030**	**5.012**	**4.719**	**562.012**	**0.192**
Coefficient of Variation				**0.06%**	**8.23%**	**1.31%**	**2.30%**	**0.22%**	**2.16%**

FUEL	Run #	Date		bhp-h	THC g/bhp-h	NOx g/bhp-h	CO g/bhp-h	CO2 g/bhp-h	PM g/bhp-h
Cert Lot # 0KP05202	5989	4/4/01	H	21.839	0.030	4.847	5.235	560.8	0.241
Cert Lot # 0KP05202	5990	4/4/01	H	21.882	0.033	4.846	5.030	558.2	0.231
Cert Lot # 0KP05202	5991	4/4/01	H	21.863	0.039	4.850	5.042	559.1	0.241
Hot Average				**21.861**	**0.034**	**4.847**	**5.102**	**559.377**	**0.238**
Coefficient of Variation				**0.10%**	**13.15%**	**0.04%**	**2.26%**	**0.24%**	**2.42%**
40:1 B-20Soy in Cert / A-1	5992	4/4/01	H	21.761	0.032	4.863	5.284	564.1	0.232
40:1 B-20Soy in Cert / A-1	5993	4/4/01	H	21.765	0.029	4.830	5.364	564.5	0.236
40:1 B-20Soy in Cert / A-1	5994	4/4/01	H	21.799	0.037	4.852	5.325	562.6	0.232
Hot Average				**21.775**	**0.033**	**4.848**	**5.324**	**563.746**	**0.233**
Coefficient of Variation				**0.10%**	**12.34%**	**0.35%**	**0.75%**	**0.18%**	**1.08%**
20% SoyGold in Cert lot OKPO5202 + 0.2%wt USDA-2	5995	4/5/01	H	21.794	0.024	4.904	5.044	558.7	0.225
20% SoyGold in Cert lot OKPO5202 + 0.2%wt USDA-2	5996	4/5/01	H	21.791	0.030	4.879	4.755	561.1	0.209
20% SoyGold in Cert lot OKPO5202 + 0.2%wt USDA-2	5997	4/5/01	H	21.782	0.029	4.887	4.836	560.4	0.213
20% SoyGold in Cert lot OKPO5202 + 0.2%wt USDA-2	5998	4/5/01	H	21.791	0.029	4.904	4.750	560.0	0.210
Hot Average				**21.790**	**0.028**	**4.894**	**4.846**	**560.051**	**0.214**
Coefficient of Variation				**0.02%**	**9.74%**	**0.26%**	**2.84%**	**0.18%**	**3.49%**
Cert Lot # 0KP05202	6000	4/6/01	H	21.825	0.029	4.880	5.473	558.7	0.233
Cert Lot # 0KP05202	6001	4/6/01	H	21.840	0.033	4.822	5.135	558.0	0.223
Cert Lot # 0KP05202	6002	4/6/01	H	21.827	0.027	4.855	5.550	560.5	0.240
Hot Average				**21.831**	**0.030**	**4.852**	**5.386**	**559.078**	**0.232**
Coefficient of Variation				**0.04%**	**11.31%**	**0.59%**	**4.09%**	**0.23%**	**3.68%**
K50 (50% Kerosene + 50% SoyGold) + 2.3% vol. DTBP	6003	4/6/01	H	21.425	0.029	4.739	3.396	556.5	0.092
K50 (50% Kerosene + 50% SoyGold) + 2.3% vol. DTBP	6004	4/6/01	H	21.432	0.030	4.688	3.185	555.5	0.083
K50 (50% Kerosene + 50% SoyGold) + 2.3% vol. DTBP	6005	4/6/01	H	21.442	0.029	4.678	3.175	555.9	0.078
Hot Average				**21.433**	**0.029**	**4.701**	**3.252**	**556.004**	**0.084**
Coefficient of Variation				**0.04%**	**2.41%**	**0.69%**	**3.84%**	**0.09%**	**8.56%**
Cert Lot # 0KP05202	6010	4/10/01	H	21.866	0.024	4.820	5.289	557.6	0.253
Cert Lot # 0KP05202	6011	4/10/01	H	21.849	0.023	4.816	5.044	558.3	0.250
Cert Lot # 0KP05202	6012	4/10/01	H	21.840	0.029	4.803	5.099	558.9	0.254
Hot Average				**21.852**	**0.025**	**4.813**	**5.144**	**558.237**	**0.252**
Coefficient of Variation				**0.06%**	**12.10%**	**0.18%**	**2.51%**	**0.12%**	**0.68%**
20% SoyGold in Cert lot OKPO5202	6013	4/10/01	H	21.810	0.018	4.947	4.660	558.2	0.197
20% SoyGold in Cert lot OKPO5202	6014	4/10/01	H	21.786	0.026	4.895	4.843	559.3	0.206
20% SoyGold in Cert lot OKPO5202	6015	4/10/01	H	21.812	0.025	4.896	4.850	559.4	0.201
Hot Average				**21.803**	**0.023**	**4.913**	**4.784**	**558.961**	**0.201**
Coefficient of Variation				**0.06%**	**17.82%**	**0.61%**	**2.25%**	**0.12%**	**2.05%**
20% SoyGold in Cert lot OKPO5202+0.5%EHN	6025	4/19/01	H	21.832	0.019	4.805	4.781	558.9	0.244
20% SoyGold in Cert lot OKPO5202+0.5%EHN	6026	4/19/01	H	21.816	0.017	4.735	4.615	558.0	0.213
20% SoyGold in Cert lot OKPO5202+0.5%EHN	6027	4/19/01	H	21.811	0.020	4.759	4.591	556.6	0.204
Hot Average				**21.819**	**0.018**	**4.766**	**4.662**	**557.824**	**0.220**
Coefficient of Variation				**0.05%**	**9.62%**	**0.74%**	**2.22%**	**0.21%**	**9.59%**

FUEL	Run #	Date		bhp-h	THC g/bhp-h	NOx g/bhp-h	CO g/bhp-h	CO2 g/bhp-h	PM g/bhp-h
20% SoyGold in Cert lot OKPO5202	6028	4/19/01	H	21.833	0.018	4.887	4.824	557.7	0.195
20% SoyGold in Cert lot OKPO5202	6029	4/19/01	H	21.772	0.015	4.875	4.758	559.6	0.194
20% SoyGold in Cert lot OKPO5202	6030	4/19/01	H	21.782	0.019	4.870	4.560	559.1	0.191
Hot Average				**21.796**	**0.018**	**4.877**	**4.714**	**558.795**	**0.193**
Coefficient of Variation				**0.15%**	**11.28%**	**0.18%**	**2.91%**	**0.18%**	**1.18%**

APPENDIX D: REFERENCES

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13. ABSTRACT *(Maximum 200 words)* A number of studies have shown substantial particulate matter (PM) reductions for biodiesel, but also a significant increase in nitrogen oxides (NO_x) emissions. This study examines a number of approaches for NO_x reduction from biodiesel.			
14. SUBJECT TERMS Biodiesel; heavy duty engine emissions; nitrogen oxides (NO_x); particulate matter (PM)			15. NUMBER OF PAGES 16. PRICE CODE
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298-102

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OP_SUNPOWER1_70

April 23, 2018

California Air Resources Board
Sacramento, CA

RE: Proposed Amendments to the Low Carbon Fuel Standard Regulation

Submitted Electonically to http://www.arb.ca.gov/lispub/comm/bclist.php

SunPower Corporation submits the following comments related to the California Air Resources Board's (CARB's) Proposed Amendments to the Low Carbon Fuel Standard Regulation.

SunPower is a California-based manufacturer with 30 years of market experience providing complete solar solutions and services to a diverse group of customers: residential, businesses, governments, schools and utilities.

Our comments pertain to the treatment of renewable electricity used in both conventional fuel refinery operations and crude production as well as for electric vehicle (EV) charging.

Boundary Conditions for Receiving Renewable Electricity Credits

The LCFS regulations allow for program participants to receive LCFS credits for utilizing renewable electricity in both conventional fuel refinery operations and crude production. This is an important policy to further drive private adoption of renewable energy to help meet the state's climate goals. 70-1

However, these rules are unjustifiably limiting in how renewable generation can qualify. For example, for solar and wind electricity projects, § 95489(c)(1)(A) indicates that electricity from such projects "must be produced and consumed onsite" in order to qualify for credits. Established state policy on net energy metering (NEM) affords a customer the ability to size an on-site renewable generator to meet up to 100% of the customer's annual electricity load. Whatever electricity is not utilized instantaneously behind-the-meter can be exported to the grid and utilized by the customer's operation at another time. We recommend that this regulation be revised (or clarified) to allow *the total output* of an on-site renewable generation system to qualify for LCFS credits. 70-1a

Likewise, the prohibition against receiving LCFS credits for renewable electricity procured from an off-site project and delivered to serve on-site refinery or crude production loads should be eliminated. There is no meaningful climate benefit distinction between renewable electricity generated from an on-site system and that from an off-site system. The important point is fostering and fulfilling the increased private demand for renewable energy being created by the refinery or crude production operation. This would also align with the staff proposal "to allow 70-2

SunPower Corporation | 1414 Harbour Way South | Ste. 1901 | Richmond, California 94804
sunpower.com

renewable power generated in the same balancing authority as the ZEV load to be used in EV charging and H2 production."[1]

70-2 continued from last page, continues to footnote below

Renewable Electricity Credit for EV Charging

SunPower supports the staff proposal to allow credit generators, such as EV manufacturers and charging station providers, within the electricity pathway to match EV charging with renewable electricity to generate LCFS credits using a zero Carbon Intensity value. This will provide an additional incentive for consumers to make EV purchases as well as support the continued deployment of renewable energy to meet the state's aggressive clean energy and climate goals.

70-3

Protecting Against Double Counting

SunPower agrees with previously submitted comments by Center for Resource Solutions (CRS) highlighting the importance of verification using established REC accounting principles to safeguard against double counting of the environmental attributes associated with the aforementioned uses of renewable energy.[2]

70-4 continues to footnote below

Thank you for your consideration.

Sincerely,

Blair G. Swezey
Senior Director
U.S. Market Development and State Policy
(510) 260-8552
blair.swezey@sunpower.com

[1] CARB *NOTICE OF PUBLIC HEARING TO CONSIDER PROPOSED AMENDMENTS TO THE LOW CARBON FUEL STANDARD REGULATION AND TO THE REGULATION ON COMERCIALIZATION OF ALTERNATIVE DIESEL FUELS*, Page 7

70-2 continued from above

[2] *Comments of Center for Resource Solutions (CRS) following the November 6, 2017 Public Workshop on the California Air Resources Board (ARB) Preliminary Draft of Potential Regulatory Amendments to the Low Carbon Fuel Standard (LCFS)*, dated December 4, 2017.

70-4 continued from above

OP_NRDC1_81

April 23, 2018

Mary Nichols, Chairman
California Air Resources Board
1001 I Street, PO Box 2815
Sacramento, CA 95812

RE: The Low Carbon Fuel Standard Regulation and the Regulation on Commercialization of Alternative Diesel Fuels

Dear Chairman Nichols and Members of the Board:

Thank you for your commitment to cleaner, healthier air for all Californians and for your international leadership in protecting current and future generations from the impacts of climate pollution. NRDC appreciates the work of the Board and staff to extend the Low Carbon Fuel Standard (LCFS), a key program to meet the state's carbon pollution reduction requirements under AB 32 and SB32. We respectfully submit these comments for your consideration. 81-1

The LCFS, in combination with the regulation on the commercialization of alternative diesel fuel (ADF) (ADF), establishes a direct, long-term regulatory structure to enable a transition to ultra-low, carbon-intensity (CI) fuels. The continued extension of the program to 2030 is critical to help ensure the state's public-health, air quality, and climate goals are met. California's program is also providing a model for other jurisdictions.

NRDC's analysis of ARB's compliance data shows that since 2011 through 3Q2017, the LCFS has helped California:

- Avoid about 33 million metric tons of greenhouse gas emissions, and almost 10 billion gallons of petroleum.[1]
- Increase investment in the clean fuels market—including production and distribution—by an estimated $2 billion, leading to an increase in alternative fuel use by 64 percent.[2]
- The LCFS, when combined with other strategies like cap-and-trade and clean vehicle standards, is delivering public health benefits that will continue to grow over time.

[1] Calculated from California Air Resources Board, *2017 LCFS Reporting Tool, Quarterly Data Summary, Report No. 3*, https://www.arb.ca.gov/fuels/lcfs/dashboard/quarterlysummary/20180131_q3datasummary.pdf
[2] Calculated from ARB's quarterly compliance data which tracks industry performance.

- Make clean low carbon fuels more accessible and economically viable for fleets, such as local transit and fleet operators as well as everyday consumers.
- Increase the diversity of fuel supplies used and reducing its reliance on petroleum, thereby making the state less vulnerable to global oil price volatility as well as refinery outages.

1. We support staff's proposal to increase the requirement to a 20 percent carbon-intensity reduction by 2030. New analysis points to an even higher target being possible.

NRDC supports staff's proposal to reduce the CI of both gasoline and diesel fuels 20 percent by 2030. A consultant report by Cerology (2018) "California's Clean Fuel Future: Assessing Achievable Fuel Carbon Intensity Reductions Through 2030," confirms that staff's feasibility assessment is not only reasonable, but is conservative.[3] We recommend that ARB consider future upward adjustments to the standard if more rapid progress is made based on compliance data. At the same time, we also ask ARB to continue to monitor the progress of similar clean fuel standards in other major jurisdictions, such as Canada, to update its supply assessment of low-carbon fuel supplies for California.

81-2 continues below and in footnote below

We also support staff's adjustment to enable the ramp to increase ever year in a linear-fashion over time between the entire 2018 to 2030 period, as opposed to an earlier proposal that would have kept the standards flat between 2020-2022 at a 10% level. Doing so will provide low-carbon fuel providers a consistent signal over time while also allowing a smooth ramp up over the entire period.

81-3

Establishing strong signals now for the post-2020 timeframe is consistent with the transformational policies outlined by ARB under its First Update to the AB 32 Scoping Plan. California's near-term efforts to establish a strong market for clean, low carbon fuels are critical to make sure the state is on the pathway to the deeper reductions needed to meet the 2050 goals.

81-2 continued from above

2. We support staff's addition of electricity pathways that recognize the potential to utilize 100% renewable electricity. We urge ARB to implement strong provisions for verify those pathways.

The success of the LCFS is in part due to the ability – within reasonable administrative limits – to recognize the many different potential pathways to reduce carbon-intensity. When coupled with 100% renewable electricity, electric passenger vehicles, trucks, and buses (collectively "EVs") have the potential to be zero-emitting on a lifecycle basis. We support ARB's proposal to recognize additional investments needed to link additional renewable electricity with EV charging.

81-7

The Board and staff should continue to monitor the implementation of this new program, whereby staff is proposing a "Green Tariff Shared Renewables Program" (GTSRP) as a way of verifying additional renewable usage. SB100 requires that utilities already increase the renewable electricity mix to 40%

[3] https://www.arb.ca.gov/lispub/comm/bccomdisp.php?listname=lcfs18&comment_num=5&virt_num=5

81-2 continued from above

renewables by 2030, such that the LCFS should only credit additional, incremental renewable electricity contracts under any type of verification program.

We agree these incremental credits – beyond a baseline – should go to entities that are making the investments that are enabling EV customers to procure the additional renewables and that are providing the necessary verification and reporting data. It is unclear, at this early date, what entity will ultimately be most successful at enabling this effort. We support staff's recommendation to keep this open to either auto manufacturers, utilities, or charging station providers. 81-7 cont.

3. We recommend that ARB provide further clarification and a review of the proposed provisions around "non-residential EV charging" and "Time-of-Use" electricity pathways.

NRDC supports staff's efforts to increase the participation in the LCFS for non-residential EV charging by fleets or public/workplace charging. However, the provisions allow for any entity to claim credits that go unclaimed, without sufficient provisions to ensure that the workplaces, fleets, or public charging companies are notified of the value of the credits and the transfer of those property rights to the claiming entity. We recommend that the Board and staff work to ensure that the system is not abused by entities that may simply collect credits. 81-8

As an alternative, ARB could develop a methodology to estimate the amounts of electricity unclaimed and assign those credits to regulated utilities or charging providers, all of whom are required to provide the LCFS value back to the benefit of EV customers. ARB could also allow entities who have existing rebate programs for charging infrastructure or electric vehicles to identify those unclaimed credits for purposes of those rebate programs.

On time-of-use charging, NRDC notes that there is significant research on the capability for utilities to integrate additional renewables through managed EV charging, including use of demand response. While there is a large potential, it is unclear how the additional for TOU charging would be additional if GTSRP programs that already credit for incremental electricity are fully utilized. We recommend that ARB make the TOU charging provisions a pilot program, pending a third-party reviewer analyzing the effectiveness of the provision based on the first two years of data, to ensure that the credits generated are truly enabling renewables that would have been curtailed otherwise. 81-10

4. ARB should work to develop and implement an EV credit program that is state-wide, consistent, and that results in an upfront "clean fuels reward" for EV customers toward the purchase or lease of an electric vehicle or charging infrastructure. 81-11 continues below

NRDC supported the development of regulatory principles early-on in the development of the LCFS to help ensure that parties receiving EV LCFS credits would ultimately use proceeds to benefit current and future EV customers making the switch to clean electricity. NRDC agrees with utilities, NGOs, and automakers that six years later, the program could improve its efficacy and effectiveness in terms of expanding the EV transportation market. At the same time, we are cognizant that regulated parties have 81-12 81-11 continued from above, continues to next page

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already established programs that are in place and that EV customers are starting to receive benefits. We ask the Board to direct ARB staff to develop a solution that captures the input from utilities, automakers, charging service providers, and NGOs in a timely, deadline-driven manner that meets the following objectives.

- Point-of-sale, clean fuels reward:
  - LCFS credits generated should go to increasing customer adoption of electric vehicles (passenger vehicles, trucks, buses, goods movement vehicles) to increase the use of electricity as a clean fuel.
  - Based on their express choice, EV customers should be able to select either a lump sum "clean fuels reward" that could go towards the purchase or lease of an electric vehicle or the purchase of charging infrastructure, ideally provided at the point-of-sale.
- State-wide consistency and reach
  - The clean fuels reward program should work the same for all California EV customers across utility boundaries and apply to all automakers selling electric vehicles. Additional state-, utility-, or automaker-specific programs could still be layered upon the baseline LCFS reward. But at its core, the LCFS clean fuels reward program should be well advertised, transparent, and easy to understand. 81-11 cont.
- Increased fairness
  - The amount of EV reward should correspond with the expected electric miles traveled or, more accurately, the GHG emissions avoided from that electric vehicle model based on the footprint. ARB should simply provide a table for the reward amounts that models would receive so that a 240-mile EV is credited fairly versus a 15-mile plug-in hybrid, for example.
  - The clean fuels reward should also encourage increased EV access and affordability in low-income, disadvantaged communities
- Higher-impact
  - The LCFS clean fuels reward should be supportive of regulated entities bringing the stream of credit value up-front (i.e. providing 3+ years of credit value).
  - ARB could consider allowing a "LCFS balancing account" to be used for electricity that have a very-high likelihood for future credit generation. ARB could consign three years or more of credit generation to the EV regulated entity at a discounted amount, with those regulated entities in turn agreeing to have future credits retired.

5. We support allowing alternative jet fuel to opt-in to the program

We support CARB's proposal to allow alternative jet fuel (AJF) to generate LCFS credits as an opt-in fuel. We mirror stakeholder comments on this issue, namely:

"By including low carbon AJF in the program, CARB will stimulate the development of biofuels for a sector of transportation that may lack other effective options for decarbonization and help California attain its greenhouse gas reduction goals." 81-13

NRDC also notes that the inclusion of alternative jet fuel will also prevent the effects of encouraging a refinery to produce on-road renewable diesel in lieu of renewable-based jet fuel, allowing the refinery to optimize the production based on demand from fleets.

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As a separate stakeholder comment letter notes, "By sending a clear and long-term market signal that AJF is eligible to generate LCFS credits in addition to Renewable Fuel Standard credits (known as RINs), CARB is facilitating investment and development in the de-carbonization of the aviation sector. This pioneering work by California is crucial given the anticipated growth of the aviation sector, the technical and energy intensive demands of this sector, and the dependence of this transportation sector on liquid fuels. 81-13 cont.

As noted in the staff proposal, existing data suggests that the use of **AJF may reduce criteria pollutant emissions during taxi, takeoffs and landings.** Increased use of AJF in the future could provide significant air quality and health benefits to local air sheds, including to disadvantaged communities located near airports. Such ancillary benefits are a powerful incentive for including AJF in the LCFS. We anticipate that the details and scope of the criteria pollutant reductions will be more accurately modeled, measured and quantified as the scale of AJF production and use in California is expanded." 81-13a

6. ARB's CEQA analysis of the NOx emission, based on expert third-party review, is conservative.

NRDC supports the CEQA analysis of the LCFS and ADF rules as being conservative. The agency has diligently attempted to identify and remediate any potential past NOx increases due to biodiesel use as well as to mitigate any potential future NOx increase from additional biodiesel use. An independent, third-party technical review of ARB's CEQA analysis by Sonoma Technologies, Inc will be submitted separately. STI has worked with government agencies and industry over the past 35 years around air quality studies, measurements, regulatory and data support, in addition to conducting CEQA trainings for government agencies. 81-14

NRDC also notes that the focus on biodiesel by itself, in part, provides only a narrow and limited view of the LCFS in its entirety in terms of impacts to public health. Overall, the program is expected to reduce criteria emission pollutants by substituting cleaner fuels for petroleum-based fuels, including use of clean electricity, hydrogen, renewable diesel, and biogas. With additional ADF requirements to use NOx reducing additives in biodiesel, the program in its entirety will ultimately result in even lower criteria emission pollutants versus a no-LCFS case. 81-15

7. NRDC supports the inclusion of accounting and permanence requirements for ethanol facilities, petroleum refineries, and crude oil producers that reduce their carbon intensity using carbon capture and sequestration.

Carbon capture and sequestration technologies have the potential to be a crucial tool in efforts to keep global temperature rise below 2 degrees centigrade, consistent with the Paris Accord. Several carbon dioxide sources in the liquid fuel supply chain, including oil extraction and refining, and ethanol production, provide especially promising opportunities for capturing and sequestering carbon dioxide. A 81-16 recent report prepared by Cerulogy Research for NextGen Policy Center showed significant potential for the technology to be deployed and contribute towards achieving LCFS targets.[4]

The Board voted years ago to allow all fuel producers to capture and sequester carbon dioxide from their own operations as another way to broaden the range of strategies employed to reduce fuel-production emissions. Pursuant to past direction by the Board, ARB staff has now devoted several years' worth of work into developing the technical framework that will be used to ensure permanence of the sequestration and govern the relevant accounting. We welcome ARB's efforts, and have actively participated in every step to date. 81-16 continued from previous page, continues to footnote below

The proposed CCS Protocol under the LCFS represents the most comprehensive piece of CCS regulation by any jurisdiction, and goes to great lengths to ensure the safe and sound selection, operation, decommissioning and monitoring of CCS projects. NRDC has devoted considerable time and attention to the science and regulation of CCS for well over a decade now, and are encouraged by the level of detail, prevention and diligence that ARB has incorporated into the Protocol. We are providing separate technical comments on ways to further improve the Protocol, and encourage ARB to ensure that environmental risks are mitigated without erecting prohibitively large barriers to developing projects that would further the achievement of California's climate goals.

8. NRDC supports the inclusion of provisions that will result in direct emission reductions from refineries and crude oil facilities

Since 2012, NRDC has supported CARB's efforts to establish credits for GHG emission reductions from refinery improvement and crude oil emission reduction projects, and we have at times worked and joined together with labor organizations under Blue-Green Alliance. Credits for refinery improvements represent a significant opportunity to spur additional investments that improve the environmental performance of refineries and that create secure refinery jobs, while reducing the carbon-intensity of transportation fuels and fostering additional benefits such as reductions in criteria pollution. To that end, we asked ARB in 2015 to help ensure that the projects represent actual capital investments to reduce carbon emissions (as opposed to simply shutting down units), creating net reductions in carbon-intensity across the refinery, and be limited to projects undertaken to help comply with the standards beyond business-as-usual, and to demonstrate the projects would meet local restrictions around air quality and criteria emissions.[5] We thank ARB for working diligently to add provisions to help ensure we can achieve multiple benefits. At the same time, we urge ARB to continue to require from parties that the reductions are real and verifiable, consistent with maintain the integrity of the program. 81-17 continues to footnote below 81-18

9. NRDC strongly supports the inclusion of a third-party verification program to ensure accurate, robust reporting.

The LCFS is one of the world's most effective programs at incentivizing companies to lower the carbon-footprint of their products in a performance-based, data driven manner. As the value of the LCFS credit 81-19

[4] https://www.arb.ca.gov/lispub/comm/bccomdisp.php?listname=lcfs18&comment_num=5&virt_num=5 81-16 continued from above
[5] NRDC and Blue Green Alliance (February 17, 2015). Letter to the Board. 81-17 continued from above

market has increased, and as the breadth of projects have grown, it is incumbent on ARB to create a verification system that enhances the program's integrity.

We support ARB's efforts to ensure that regulated entities generating more than a *de minimis* amount of reduction credits provide third-party verification around the data reported to ARB, including site-specific annual visits. We support ARB's efforts to also require independent third-parties to participate in training and to have no conflicts of interest. Doing so will allow the performance-based, technology neutral flexibility that ARB provides to allow for companies to credit their innovations and improvements, while enabling the administrative aspects to be handled in manageable fashion. 81-19 cont.

In closing, we urge ARB continue its decade long support of the LCFS and extend it into the next decade. Climate policy solutions for the transportation sector are needed in California, in other states, across the nation, and around the world. ARB must continue its longstanding leadership role by sending a strong signal that California will move forward – together with other subnational and national jurisdictions. 81-20

Sincerely,

Simon C. Mui

Senior Scientist, Ph.D.

Clean Vehicles & Fuels, California

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OP_AJFP1_102

NOYES LAW CORPORATION

April 23, 2018

The Honorable Mary D. Nichols
Chair, Air Resources Board
1001 I Street
Sacramento, CA 95812

RE: Proposed LCFS Regulations Pertaining to Alternative Jet Fuel

Dear Chair Nichols:

The alternative jet fuel producers (the "AJF Producers") appreciate the opportunity to provide comments regarding the Low Carbon Fuel Standard ("LCFS") regulations under consideration by the Air Resources Board ("ARB"), pertaining to the inclusion of alternative jet fuel ("AJF") in the LCFS. This comment integrates some aspects of comments we previously submitted to the LCFS workshop process, and supersedes all of our prior informal comments to this rulemaking. The AJF Producers have worked closely and cooperatively with Airlines for American ("A4A") throughout the rulemaking process, and join the separately submitted comments of A4A.

Summary of Comment

The primary purpose of this letter is to express our strong support for the inclusion of AJF in the LCFS, and to acknowledge the exemplary work of ARB staff and management in working with the AJF Producers, A4A, and the aviation industry. We literally have been working with the ARB for two years in the development of this rule. Throughout this time, we have communicated steadily through numerous public workshops, meetings, informal written comments, phone calls, and emails. ARB has been actively engaged throughout this process and has thoroughly considered and integrated our input into the proposed rule. Overall, we heartily recommend adoption of the AJF regulatory proposal as proposed and concur with the specifics of the proposed regulatory structure pertaining to the rule. 102-1 102-1a

There is one significant remaining issue pertaining to carbon intensity that justifies further review from both technical and policy perspectives. The technical aspect involves the assumptions underlying the California GREET3.0 ("CA-GREET") carbon intensity ("CI") benchmark score proposed for conventional jet fuel. Based on analysis of jet fuel refining that industry technical experts have developed, it is 102-2

401 SPRING STREET, SUITE 205
NEVADA CITY, CA 95959
(530)264-7157

our conclusion that ARB has assumed the refinery efficiency attributable to conventional jet fuel to be approximately 5.5% more efficient than real world operations support. The practical impact of establishing a benchmark that is 5.5% too low from a technical perspective is that eligible AJF producers will generate 5.5% fewer credits than are technically justified. In a fuel commodity world that operates on basis points, a 5.5% differential is a substantial one. 102-2 cont.

The closely related policy issues pertain to the starting point and the shape of the carbon intensity curve that ARB establishes for AJF. In particular, ARB has proposed a CI curve with the same downward slope as the petroleum diesel curve even though ARB does not have regulatory authority over the CI of jet fuel. In addition, ARB has proposed a CI curve that "catches up with" the decline in the diesel curve even though AJF could not generate credits during the first eight years of the LCFS program. As a net result of these two policy decisions coupled with the unfavorable CI determination, ARB is proposing CI benchmarks for AJF that are 11% below the diesel benchmarks through 2030. If approved, the resulting Table 3 of the proposed rule would therefore result in 11% less credit generation per gallon for AJF than on-road renewable diesel fuel. 102-3

It is our impression that ARB has exercised both its technical and its policy discretion to disfavor AJF from a crediting perspective out of an abundance of caution. The underlying concern identified in the initial statement of reasons is the potential risk of diversion of fuel production from the on-road sector (renewable diesel or "RD") to the aviation sector (alternative jet fuel or "AJF").[1] In response to this concern, the decision has been taken to set the CI benchmarks for AJF in a manner that discounts credit generation opportunities so that not a single drop of California's on-road RD fuel supply is diverted into the aviation market.

We respect the diligent environmental stewardship that underlies this approach and do not question the underlying objective. However, there is an existing economic framework that very effectively protects California's on-road renewable diesel fuel supply. This economic framework consists of a durable combination of factors including production economics, fuel specifications, market forces, California climate policies, and the federal Renewable Fuel Standard (RFS). This comment describes and explains these various factors and provides empirical data to substantiate the economic value of each factor. Taken as a whole, these factors demonstrate that AJF production will remain significantly disadvantaged compared

[1] As noted in the ISOR, some stakeholders expressed concern that "if supply of low carbon biomass feedstocks is limited, AJF production may compete with production and on-road use of biomass-based diesels…" ARB ISOR, Appendix D: Draft Environmental Analysis at 66-67.

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to on-road fuel even after AJF becomes eligible to generate LCFS credits. We request that ARB closely examine this economic framework; recognize that it provides ample protection to California's renewable diesel supply; and proceed to establish LCFS crediting parity for AJF production.

102-3 continued from previous page, continues to page 6

Overview of AJF Producers

The AJF Producers joining this letter are AltAir Fuels, Fulcrum BioEnergy, Neste, Red Rock Biofuels, and Velocys. California-based AltAir Fuels is the only dedicated renewable jet fuel refiner in the world, and is supplying commercial quantities of alternative jet fuel to United Airlines at Los Angeles International Airport (LAX) from the AltAir production facility in Paramount. Fulcrum BioEnergy is developing a facility in Reno, Nevada, and plans to supply AJF into the California market. Neste is the largest existing producer of renewable diesel for the California market and has the capability to produce alternative jet fuel. Red Rock Biofuels is developing a production facility capable of producing alternative jet fuel in Lakeview, Oregon and plans to supply AJF into the California market. Velocys provides small-scale modular Fischer-Tropsch technology to alternative jet fuel producers, and is itself developing production facilities.

Strong Support for Inclusion of AJF in the LCFS

The AJF Producers are highly supportive of the LCFS program and of ARB's proposal to facilitate LCFS credit generation through opt-in participation for AJF uplifted in California. The LCFS has proven to be an effective, market-based program that has driven the development and expanded the supply of low carbon fuels in California. By including low carbon alternative jet fuels in the program, ARB will further expand the supply of less carbon-intense fuels and facilitate attainment of California's greenhouse gas ("GHG") reduction policies. By sending a clear and long-term market signal that AJF is eligible to generate LCFS credits in addition to Renewable Fuel Standard ("RFS") credits ("RINs"), ARB is facilitating investment and development in the decarbonization of the aviation sector. This pioneering work by California is crucial given the anticipated growth of the aviation sector, and the technical and energy intensive demands of this sector.

102-5

Technical Input Regarding Carbon Intensity of Conventional Jet Fuel

As noted in the summary, it is our position that from a technical perspective the proposal has incorrectly calculated the carbon intensity score for conventional jet fuel in California. Based on the CA-GREET3.0 Supplemental Document and Tables of Changes (March 6, 2018), the refining efficiencies used for petroleum jet fuel and ultra-low sulfur diesel fuel ("ULSD") in CA-GREET3.0 are 94.9% and

102-6

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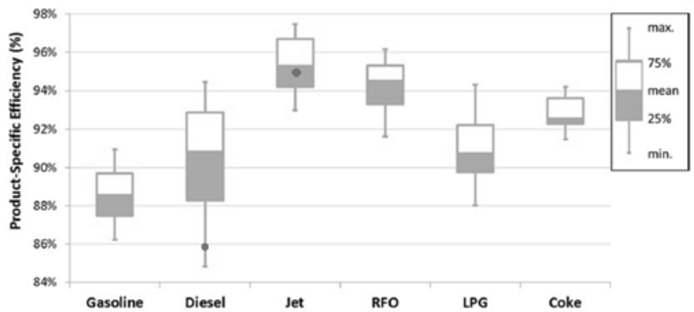
85.87% respectively. The 9.03% difference in efficiency is a substantial difference between two very similar middle distillate products produced at the same California refineries. The efficiency difference is not sufficiently supported in the record to enable a complete response. However, the figures appear to be based on Linear Programming (LP) results for California refineries provided by Argonne. What appears to be the primary technical reference in the ISOR for the refinery effiency assumptions[2] includes the following table as Figure 7.

Figure 7. Average product shares (by energy) from major processing units in 43 refineries.



102-6 cont.

The original table does not include the two red dots which have been added here to illustrate the refining efficiencies used for petroleum jet and ULSD in CA-GREET3.0. This figure illustrates that the ULSD refining efficiency used to establish the CI value for conventional jet fuel represents a value close to the low-end of the diesel range; whereas the jet refining efficiency is close to the mean value of the jet range. The same underlying Argonne technical paper also indicates that the difference between production-weighted average efficiencies of diesel and jet fuel is 4.4%. In contrast, ARB selected a difference of 9.03% for its modeling in CA-GREET3.0, more than double the difference in the Argonne GREET paper.

In the underlying technical paper, Elgowainy et al. state that "The wide range of diesel efficiencies is attributable to the various pathways for diesel production in refineries. When less diesel yield is desired, the production pathway becomes more efficient because a larger share of the diesel product is produced directly from the distillation tower. However, when more diesel production is desired, a larger share

[2] ISOR, p. XII-19, footnote 53 provides the following reference from which the table has been extracted: "Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries," Amgad Elgowainy, Jeongwoo Han, Hao Cai, Michael Wang, Grant S. Forman, Vincent B. Divita, May 2014. https://greet.es.anl.gov/publication-energy-efficiency-refineries .

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of the diesel product comes from the hydrocracker (with extensive hydrogen use), the coker, and the FCC units."[3]

This same reasoning appears equally applicable to petroleum jet. To better explain its technical approach, ARB should provide more information about the sensitivities of the LP model used. For example, ARB should indicate the refining efficiency for the marginal petroleum jet in the event that jet fuel demand is higher than assumed.

As the refining efficiency is a key parameter when determining the CI of producing a petroleum product, the following changes should be made to CA-GREET3.0 to reflect the impact of a more accurate refining efficiency assumption. Two different cases are specified below. 102-6 cont.

Case A:
- Petroleum jet fuel efficiency changed from 94.9 to 91.1%.[4]
- Refinery still gas consumption to reflect the change in efficiency.[5]
- Petcoke consumption to reflect the the change in efficiency[6]

Resulting CI of conventional petroleum jet in 2010 is 94.04 gCO2e/MJ.

Case B:
- Petroleum jet fuel efficiency from 94.9 to 86.4%, if which case the difference between ULSD at 85.9 and petroleum jet would be 0.5 percentage points. The difference of 0.5% in refining efficiency of diesel and jet is mentioned in the paper by Palou-Rivera et.
- Same changes as in case A regarding still gas and petcoke consumption

Resulting CI of conventional petroleum jet in 2010 is 99.00 gCO2e/MJ.

Accordingly, ARB has assumed the refinery efficiency attributable to jet fuel to be approximately 5.5% more efficient than real world operations support resulting in a 2010 CI score of 89.84. This incorrect assumption inappropriately discounts the CI

[3] "Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries," Amgad Elgowainy, Jeongwoo Han, Hao Cai, Michael Wang, Grant S. Forman , Vincent B. Divita, May 2014. https://greet.es.anl.gov/publication-energy-efficiency-refineries .

[4] The figure of 91.1% is based on a paper by Palou-Rivera et. al, Updates to Petroleum Refining and Upstream Emissions, Argonne National Laboratory 2011. https://greet.es.anl.gov/files/petroleum

[5] The CA-GREET3.0 spreadsheet reference here is JetFuel_WTP Cell: C264 Petroleum!$AV120*(1/B$227-1)/(1/Petroleum!$AU$82-1)

[6] The CA-GREET3.0 reference is Sheet: JetFuel_WTP Cell: C260 Petroleum!$AV115*(1/B$227-1)/(1/Petroleum!$AU$82-1)

of jet fuel as compared to on-road diesel resulting in lesser credit generation opportunities for AJF. While both cases illustrated rely upon reasonable assumptions about the real world refining efficiencies, the AJF Producers respectfully submit that the appropriate refining efficiency for use in setting the AJF baseline should be 91.1%. This approach is illustrated by Case A and is strongly supported and justified in the technical literature including the paper cited by ARB in the ISOR. 102-6 cont.

After setting the baseline CI for conventional jet fuel for 2010, the additional step that ARB utilized in setting the CI benchmark scores for AJF for 2019 and subsequent years was to further discount the 2010 CI score by 6.25%. This discount is equivalent to the CI reductions imposed on diesel fuel from 2011-2018. As established by Table 3 of the proposed regulation, this results in a CI benchmark score of 84.23 for 2019 for crediting purposes with a decline of CI to 71.87 established for 2030 and subsequent years. 102-3 continued from page 3, continues to next page

With this technical background, it is appropriate to first review ARB's regulatory authority for the LCFS then revisit the relevant policy issues.

Regulatory Authority

The underlying authority for the LCFS is California's Global Warming Solutions Act of 2006 (AB 32) which set a goal of reducing greenhouse gas (GHG) emissions in the state to 1990 levels by 2020 and charged ARB with developing and implementing regulations in various areas to achieve that goal. In January 2007, then-Governor Arnold Schwarzenegger issued Executive Order S-01-07 calling on CARB to determine whether or not a low carbon fuel standard could be adopted as a standalone measure under AB 32. In April 2010, ARB adopted a final set of regulations for the LCFS that is now codified at Cal. Code Regs. tit. 17, §§ 95480 et seq.[7] The regulations set out a comprehensive program to reduce the carbon intensity of California's transportation fuels by at least 10% by 2020. To do this, the LCFS program establishes reporting, performance and record keeping requirements related to the full life-cycle carbon intensity of fuels sold in or imported into California.

The LCFS applies to transportation fuels that are "sold, supplied, or offered for sale in California" and to "any person who as a regulated party…is responsible for a transportation fuel in a calendar year." The LCFS applies to a wide range of transportation fuels and technologies including liquid and gaseous fuels such as ethanol, biodiesel, hydrogen and biomethane. However, the LCFS does not apply to aviation fuels. Conventional jet fuel remains excluded from the regulation pursuant to proposed §95482(c)(2) which provides an exemption for "Conventional

[7] All subsequent references to regulations in this Comment also pertain to Title 17.

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jet fuel or aviation gasoline." Similarly California's Regulation for the Mandatory Reporting of Greenhouse Gases ("MRR") at §95121(d) excludes the reporting of fuels "where use in exclusively aviation or marine applications can be demonstrated."

<u>Establishing the Optimal Benchmark for AJF Credit Generation</u>

ARB has acknowledged that its authority is markedly different in the aviation sector as compared to the on-road transportation sector. As noted in the ISOR,

> *Subjecting aircraft fuels to annual carbon intensity standards would raise federal preemption issues. However, CARB has the authority to amend the LCFS regulations to create incentives to promote the use of low carbon fuels in aircraft by allowing credit for such fuels. By promoting the voluntary production and use of alternative jet fuel, CARB would not be regulating aircraft fuels, but rather would simply be creating opportunities for airlines to better support California's GHG objectives.*[8]

102-3 continued from previous page

Recognizing the federal preemption issues, ARB is not establishing mandatory declining standards for the CI of conventional jet fuel and aviation gasoline in California. ARB is instead providing an opt-in LCFS credit generation opportunity for AJF that is intended to have the salutary effect of achieving GHG reductions in the unregulated aviation sector. While the benchmark scores in the CI tables applicable to gasoline (Table 1) and diesel fuel (Table 2) set the annual compliance standards for regulated parties and establish the rate of credit generation for low carbon fuel producers, Table 3 for conventional jet fuel only establishes the rate of credit generation for AJF producers.

Within the regulatory context of opt-in crediting, ARB has broad discretion regarding the benchmarks it sets for credit generation purposes. The approach that ARB is proposing is established by Table 3 entitled, "LCFS Carbon Intensity Benchmarks for 2019 to 2030 for Fuels Used as a Substitute for Conventional Jet Fuel." As described by the ISOR, "the AJF annual benchmarks are anchored to the 2010 baseline for conventional jet fuel and incorporate the same annual percent reductions as the benchmarks for gasoline and diesel."[9] Based on this approach coupled with the underlying CA-GREET analysis, CARB proposes to adjust the 2010 baseline of 89.84 g CO2e/MJ for jet fuel to 84.23 g CO2e/MJ for the 2019 start date of proposed the opt-in and decrease it further thereafter. Regarding the rationale for its methods of setting the carbon intensity benchmarks for AJF, the ISOR states,

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[8] CARB ISOR at III-30.
[9] CARB ISOR at II-5.

> *"To maintain consistency with the annual carbon intensity benchmark for diesel and gasoline and to create a level playing field with ground transportation fuels, staff is proposing that the annual carbon intensity benchmarks for alternative jet fuel incorporate the same annual percent reduction as the annual carbon intensity benchmarks for gasoline and diesel for 2019 through 2030."*[10]

However, given ARB' lack of authority to regulate jet fuel, consistency here is misplaced. From a policy design perspective, there are several approaches that ARB could have taken that would have yielded a better policy outcome and would have been more consistent with ARB's regulatory authority. One approach discussed during the rulemaking process would be to utilize the existing diesel curve contained in Table 2 as the applicable benchmark. This approach would place AJF credit generation on precisely the same footing as on-road renewable diesel credit generation. It would also recognize the realities of the fuel marketplace. As ARB noted in the ISOR,

> *"Second, because AJF and renewable diesel (RD) are often produced in the same facility using the same feedstock, inclusion of AJF may lead to increased investment in such facilities, thereby increasing the production of both alternative fuels."*[11]

102-3 cont.

Given that AJF and RD are often produced in the same facility, establishing the same benchmark for the two fuels would have provided both fuels with the same LCFS credit generation opportunities. Such an approach would not favor AJF production over RD production, and would not present any risk of market distortion. The AJF Producers support such an even-handed crediting mechanism, and we continue to view it as a preferred solution to the proposal.

Another benchmarking approach that would be more consistent with ARB's regulatory authority would be to establish a fixed benchmark standard for conventional jet fuel. This would be consistent with conventional jet fuel's LCFS exemption and would appropriately recognize the difference between CARB's regulatory authority over diesel and gasoline and its authority to provide a voluntary incentive in the aviation sector. Rather than a curve, such an approach would establish a fixed benchmark. It would logically be fixed at the CA-GREET 3.0 carbon intensity score that ARB determines for conventional jet fuel for 2010. As discussed in the technical section of this comment, the AJF Producers submit that the appropriate 2010 CI score for conventional jet is 94.04, whereas ARB has proposed 89.84. ARB has further proposed to reduce its benchmark of 89.84 by 6.25% which would result in a CI benchmark of 84.23 for 2019.

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[10] CARB ISOR, at III-46.

[11] CARB ISOR, at II-5.

While a fixed benchmark score is justified from a regulatory authority perspective, the AJF Producers recognize that ARB is concerned with an LCFS crediting mechanism that provides relatively more LCFS credits to alternative jet fuel than to on-road renewable diesel. We therefore would also support a hybrid approach that commences with a benchmark based on conventional jet fuel's CI score determined but declines in tandem with the diesel standard in Table 2 beginning when the CI standard for diesel fuel reaches its level.

102-3 continued from previous page, continues to page 16

- To illustrate this hybrid approach using the 2019 CI benchmark that ARB has proposed in Table 3 of 84.23, the benchmark for AJF would remain at 84.23 through 2027. Beginning in 2028 when the declining CI curve for diesel fuel goes below this CI level and in subsequent years, the CI benchmark for diesel fuel would also be the benchmark for AJF.
- To illustrate this hybrid approach using the CI score that is established by the refinery efficiency rating described in Case A of this comment (94.04) and without a 6.25% decline, the benchmark for AJF would be 94.04 in 2019, then would begin declining with the diesel CI score beginning in 2020 and for all subsequent years.

102-12

As previously noted, one concern expressed in the ISOR is the possibility of diverting production capacity from renewable diesel to AJF production. The following economic factors are described and quantified in today's market to illustrate that renewable diesel is well-protected against any such risk.

Economic Factors Applicable to the AJF Market

The economic factors applicable to the AJF Market that place AJF production at a structural disadvantage to on-road renewable diesel production are as follows:

1. Producers forecast less revenue from sales of alternative jet fuel than renewable diesel because jet fuel has historically sold at a discount to on-road diesel in the California market and future projections predict this trend will continue.
2. Due to the more stringent cold flow specification for jet fuel, alternative jet fuel requires more intensive processing than does on-road renewable diesel. Petroleum jet is relatively less burdened in meeting the jet specifications due to the inherent differences between fossil crude feedstocks and renewable jet feedstocks.
3. Jet fuel is not burdened at the rack by the cost of cap and trade allowances as is petroleum diesel. In today's market, this provides renewable diesel with an effective .15/gallon price discount to petroleum diesel that alternative jet fuel will not receive.

4. Conventional jet fuel pricing is also not burdened with the LCFS compliance cost that is assessed at the rack for conventional diesel fuel resulting in an effective .07/gallon price discount to petroleum diesel in today's market that alternative jet fuel will not receive.
5. Under the federal Renewable Fuel Standard (RFS), AJF receives relatively fewer RINs than on-road diesel with renewable diesel generating 1.7 RINs per gallon and renewable jet fuel generating 1.6 RINs per gallon. This results in a 6% discount on RIN generation representing .06/gallon less incentive per gallon in today's market.

Each of these economic factors is explained in additional detail in the following sections, with empirical support provided for each factor. Finally, the cumulative economic impact of these factors is considered with reference to the production of alternative jet fuel as compared to on-road renewable diesel. From a technology standpoint, this discussion focuses solely on alternative jet fuel that is produced via hydroprocessing which is the production process utilized by AltAir Fuels and Neste. This focus is necessary at this stage of industry development because, "Hydroprocessing technologies using vegetable and waste oils represent the only conversion pathways that are ready for large scale deployment (Leuphana 2011)."[12] 102-12 cont.

1. **Producers forecast less revenue from sales of alternative jet fuel than renewable diesel because jet fuel has historically sold at a discount to on-road diesel in the California market and future projections predict this trend will continue.**

First, outside market forces encourage renewable diesel production over AJF. The chief market force favoring diesel over jet fuel is the higher price historically commanded for diesel fuel in the spot market. Data from the U.S. Energy Information Administration (EIA) indicates that the spot price for jet fuel has historically been below the price of diesel, and the EIA anticipates this market dynamic to continue for the foreseeable future, chiefly due to tighter sulfur limits on diesel fuel (see Figure 1 below).[13] Average annual data on the prices of diesel and

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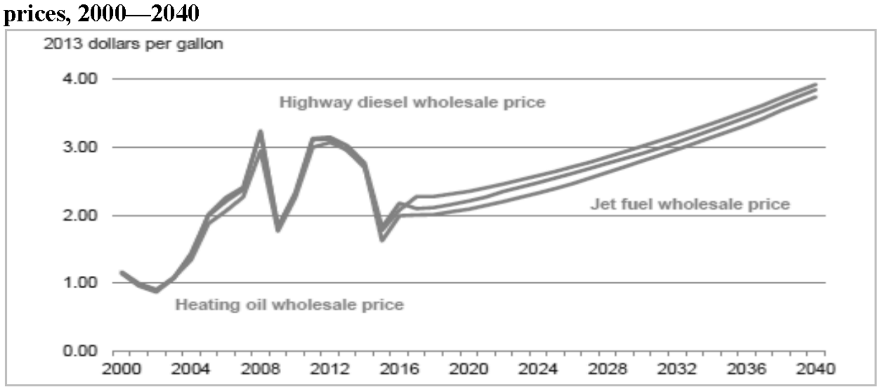
[12] National Renewable Energy Laboratory, Review of Biojet Fuel Conversion Technologies, Wei-Cheng Wang, Ling Tao, Jennifer Markham, Yanan Zhang, Eric Tan, Liaw Batan, Ethan Warner, and Mary Biddy Prepared under Task No. BB14.4420, at p. 6, available at https://www.nrel.gov/docs/fy16osti/66291.pdf .

[13] See U.S. Energy Information Administration spot price data at https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm; *see also* EIA, The Flight Paths for Biojet Fuel at 3 (noting that "non-petroleum hydrocarbons that can go into jet fuel can also be blended into diesel fuel or heating oil, both of which are projected to sell for higher prices than jet fuel in the future."). *See also*, International Renewable Energy Agency, Biofuels for Aviation at 5 (noting that producers are focused on producing renewable diesel, which has a larger market and higher sales price).

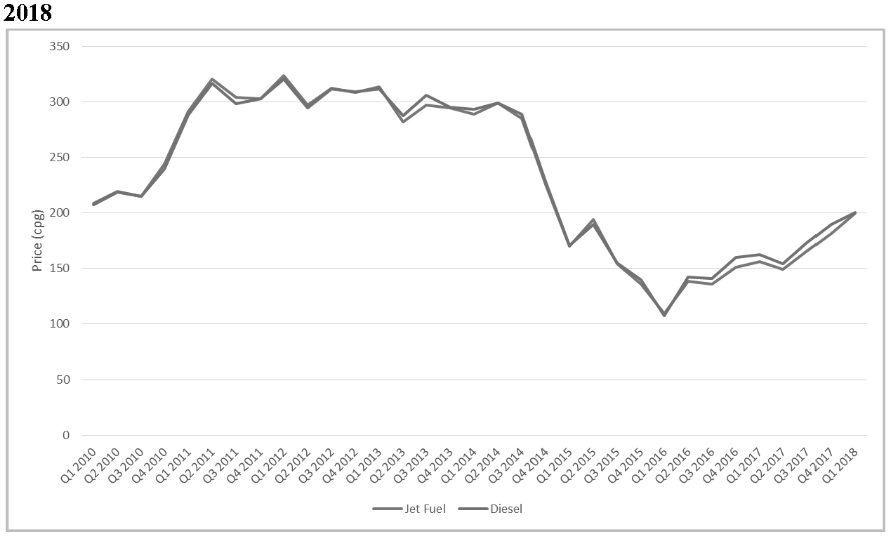
jet fuel available in Los Angeles summarized below in Figure 2 also demonstrate that the price of diesel in California generally exceeds the jet fuel price.[14]

Figure 1. EIA estimates and projections of U.S. jet fuel and distillate fuel prices, 2000—2040



102-12 cont.

Figure 2. Jet Fuel and Ultra-Low Sulfur Diesel Prices in Los Angeles, 2010—2018



[14] Data provided by Bloomberg.

2. **Due to the more stringent cold flow specification for jet fuel, alternative jet fuel requires more intensive processing than does on-road renewable diesel. Petroleum jet is relatively less burdened in meeting the jet specifications due to the inherent differences between fossil crude feedstocks and renewable jet feedstocks.**

Due to the more stringent cold flow specifications for jet fuel, alternative jet fuel requires more intensive processing than does on-road renewable diesel. The AltAir Facility in Paramount, California is the only U.S. facility that is steadily producing and supplying commercial quantities of alternative jet fuel. AltAir supplies to the common hydrant fueling system of Los Angeles International Airport pursuant to a contract with United Airlines. AltAir purposefully designed its production process to produce renewable jet. The company estimates that it costs approximately $0.16/gallon more to make renewable jet than it would cost for a comparable renewable unit configured to only make renewable diesel. Petroleum jet is less burdened in meeting the jet specification due to the inherent differences between the composition of fossil crude feedstocks (which contain molecules in the jet and diesel boiling range) as compared to renewable jet feedstocks (which rely on cracking of a diesel boiling range molecule to form a jet molecule). Although crude oil does not necessarily need to be cracked to form a jet, it does still need to be fractionated from the diesel, which costs about $0.09/gallon. The normal crack spread does not cover this differential, so there is a preference to make diesel instead of jet in most refineries. 102-12 cont.

3. **Jet fuel is not burdened at the rack by the cost of cap and trade allowances as is petroleum diesel. In today's market, this provides renewable diesel with an effective .15/gallon price discount to petroleum diesel that alternative jet fuel will not receive.**

The various market factors are best illustrated with reference to real world pricing in today's California market. The Oil Price Information Service ("OPIS") provides daily information on petroleum prices world-wide. OPIS is widely recognized in the petroleum industry as the most reliable and accurate source for spot benchmark pricing.[15] OPIS publishes a daily report on U.S. west coast rack pricing of various petroleum products at various locations in the western U.S. This report is entitled the OPIS West Coast Spot Market Report ("OPIS Market Report"). The AJF Producers appreciate that OPIS provided a limited copyright waiver approval authorizing the submission of the March 29, 2018 OPIS Market Report to be

[15] For further information on the Oil Price Information Service and its spot pricing services, see https://www.opisnet.com/about/company-overview/

included as Exhibit A to this comment, and to be made part of the rulemaking record.

On page 5 of the OPIS Market Report, OPIS posts pricing for California Cap-at-the-Rack prices. Pursuant to California's Cap-and-Trade program, petroleum diesel fuel triggers allowance obligations for the terminal position holder that sells diesel over the rack. OPIS tracks the current market value of the allowance as expressed on a cents per gallon basis. The following chart illustrates the cost of allowances reported on March 29, 2018:

Prompt Calif. Cap-at-the-Rack Prices (cts/gal)

Product	Price	Wk Avg	30-Day Avg
Summer CARB RFG-R	11.83	11.848	11.881
Summer CARB RFG-M	11.80	11.818	11.852
Summer CARB RFG-P	11.79	11.808	11.842
Winter CARB RFG-R	11.80	11.818	11.858
Winter CARB RFG-M	11.80	11.818	11.858
Winter CARB RFG-P	11.82	11.834	11.871
CARB No.2	15.03	15.052	15.099
B5 Biodiesel	14.28	14.302	14.347
Propane	8.25	8.262	8.288
LNG (cts/DGE)	10.75	10.762	10.796

The posting that is of primary importance to AJF producers from a market perspective is the CARB No.2 posting which refers to CARB Diesel. OPIS reports that the 30-day average for allowance costs attributable to a gallon of CARB Diesel was just over fifteen cents per gallon ($0.15/gallon). In contrast to petroleum diesel suppliers, renewable diesel suppliers are not obligated to purchase and retire allowances for renewable diesel that is sold over the rack or by other methods in the California market. Conventional jet fuel sold in California also does not trigger carbon allowance obligations. 102-12 cont.

The result of this cap-and-trade obligation is to provide a relative discount of renewable diesel sold into the California market, as compared to petroleum diesel. Using the March 2018 example, if the bulk fuel pricing for petroleum diesel fuel and renewable diesel fuel was equivalent at $3.00 per gallon, a purchaser of petroleum diesel would pay an additional $0.15 to cover the allowance cost resulting in a net price of $3.15, whereas a renewable diesel purchaser would pay only the $3.00 price. If conventional jet fuel was also priced that day at $3.00 per gallon, the jet fuel purchaser would pay a net price of $3.00. Thus a biorefinery capable of producing both renewable diesel and alternative jet fuel could expect to

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receive a $0.15 per gallon premium for RD sales but no such premium for AJF sales.

4. **Conventional jet fuel pricing is not burdened with the LCFS compliance cost that is assessed at the rack for conventional diesel fuel resulting in an effective .07/gallon price discount to petroleum diesel in today's market that alternative jet fuel will not receive.**

The second posting that is of importance to AJF producers from a market perspective is the OPIS California Low Carbon Fuel Standard posting. Like the Cap-at-the-rack pricing, OPIS reports the compliance costs attributable to a gallon of CARB Diesel. The following posting is from the March 29th OPIS Market Report. 102-12 cont.

OPIS California Low Carbon Fuel Standard

Product	Low	High	Mean	Change
Carbon Credit ($/MT)	140.000	145.000	142.5000	1.0000
CI Pts Ethanol ($/CI)	0.01141	0.01182	0.011615	0.000080
CI Pts Biodiesel ($/CI)	0.01766	0.01829	0.017975	0.000125
Carbon CPG Diesel (cts/gal)	6.72	6.96	6.840	0.050
Carbon CPG Dsl 95% (cts/gal)	6.38	6.61	6.495	0.045
Carbon CPG Gasoline (cts/gal)	10.43	10.80	10.615	0.075
Carbon CPG Gas 90% (cts/gal)	9.38	9.72	9.550	0.070

As listed in the report, the mean underlying LCFS price was $142.50 per metric ton during the applicable time period. This resulted in a mean compliance cost per gallon of diesel fuel of $0.068/gallon or almost seven cents per gallon. As is the case in the cap-and-trade program, renewable diesel suppliers do not accrue LCFS credit obligations. Similarly, conventional jet fuel sold in California also does not trigger LCFS obligations.

The result of this LCFS obligation is to provide a supplemental discount to renewable diesel sold into the California market, as compared to petroleum diesel. Using the same March 2018 example, if the bulk fuel pricing for petroleum diesel fuel and renewable diesel fuel was equivalent at $3.00 per gallon, a purchaser of petroleum diesel would pay an additional $0.07 to cover the LCFS compliance cost plus the cap-and-trade cost of $0.15 resulting in a net price of $3.22, whereas a renewable diesel purchaser would pay only the $3.00 price. If conventional jet fuel was also priced that day at $3.00 per gallon, the jet fuel purchaser would pay a net price of $3.00. Thus a biorefinery capable of producing both renewable diesel and alternative jet fuel could expect to receive a $0.22 per gallon premium for RD sales but no such premium for AJF sales.

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5. **Under the federal Renewable Fuel Standard (RFS), AJF generates relatively fewer RINs than on-road diesel with renewable diesel generating 1.7 RINs per gallon and renewable jet fuel generating 1.6 RINs per gallon. This represents a 6% discount on RINs. This results in a 6% discount on RIN generation representing .06/gallon less incentive per gallon in today's market.**

The Renewable Fuel Standard ("RFS) is a federal program that provides market based incentives to qualifying producers of renewable fuel by requiring petroleum refiners and importers to obtain renewable identification numbers ("RINs") based on their petroleum fuel volumes. There are multiple RIN categories in the RFS, with both renewable diesel and jet fuel typically generating D4 RINs, known as biomass-based diesel RINs. The key disadvantage that alternative jet fuel encounters under the RFS relates to the number of RINs generated compared to renewable diesel fuel generated on a per gallon basis. RD generates 1.7 RINs per gallon under the RFS, whereas renewable jet has been determined to generate 1.6 RINs per gallon.[16]

102-12 cont.

The OPIS Market Report also provides current market pricing for RINs. The RIN values are provided on an ethanol equivalent basis. The following table is applicable to RINs:

OPIS U.S. RIN Values (cts/RIN)

Product	Year	Low	High	Mean	Change
Corn Ethanol	2017	41.50	44.50	43.000	1.500
Corn Ethanol	2018	43.00	46.00	44.500	0.500
Biodiesel	2017	56.50	60.50	58.500	-1.500
Biodiesel	2018	64.00	68.00	66.000	-1.750
Cellulosic	2017	255.00	261.00	258.000	0.000
Cellulosic	2018	247.00	253.00	250.000	0.000
Adv. Biofuel	2017	55.50	59.50	57.500	-1.500
Adv. Biofuel	2018	63.00	67.00	65.000	-1.750

The applicable RIN value is listed here as "Biodiesel" with a 2016 mean price of \$0.66 per D4 RIN. Adjusting the RIN value for the energy density of renewable diesel results in a RIN value per renewable diesel gallon of \$1.056. The RIN generation discount per gallon between 1.6 RINs for AJF as compared with 1.7

[16] 40 CFR §80.1415(b)(4) provides, "Non-ester renewable diesel with a lower heating value of at least 123,500 Btu/gal shall have an equivalence value of 1.7." Regarding renewable jet RIN generation crediting of 1.6, see EPA Compliance Help 2018, "RIN Generation and Renewable Fuel Volume by Fuel Type," at https://www.epa.gov/fuels-registration-reporting-and-compliance-help/2018-renewable-fuel-standard-data

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RINs for RD results in approximately a 6% discount. Thus a RD producer would receive more than six cents per gallon ($.06) than an AJF producer would.

The result of this RFS discount is to provide an additional policy incentive to renewable diesel sold into the market, that is supplemental to the favorable California policy incentives. Using the same March 2018 example, the cap-and-trade cost of $0.15 plus the LCFS compliance cost results in a net price of $3.22, whereas a renewable diesel purchaser would pay only the $3.00 price. If conventional jet fuel was also priced that day at $3.00 per gallon, the jet fuel purchaser would pay a net price of $3.00. Thus a biorefinery capable of producing both renewable diesel and alternative jet fuel could expect to receive a $0.22 per gallon premium for RD sales but no such premium for AJF sales. In addition, the RD gallon would generate an additional $.06 in RIN value resulting in a net policy premium for RD of $0.28 as compared to AJF.

102-12 continued from previous page, continues below

Environmental analysis

The AJF producers support CARB's conclusion in the Draft Environmental Assessment conducted pursuant to 17 CCR 6005 that "[w]ithout the use of AJFs, it could be difficult to achieve long-term GHG emission reduction goals . . ."[17] in the State, and that the "likely outcome of the Proposed Amendments' inclusion of AJF is . . . that the total air quality benefit increases."[18] As further discussed in the comments of A4A, independent analysis by NREL and ACRP confirm the reduction in criteria pollutant emissions from use of AJF.

102-13 continues to footnotes below

Conclusion

As examined in some detail by this comment and supported by market data, the production of renewable diesel is inherently favored over alternative jet fuel. While we have not attempted to assign a precise figure to it, conventional jet fuel typically sells at a discount to diesel fuel in the California market and this is predicted by the U.S. Energy Information Administration to continue in the future. According to the one existing commercial producer, alternative jet fuel production results in an additional cost per gallon of about $0.07 per gallon. The combined California and federal policy factors result in $0.28 of policy premium that favors RD production. These factors are cumulative and thus the existing policy and market landscape is heavily slanted to favor RD production over AJF production.

102-12 continued from above

As currently proposed, the LCFS will slant another long-term policy in favor of renewable diesel over alternative jet fuel. Specifically, the CI benchmark values for

102-3 continued from page 9, continues to next page

[17] CARB ISOR, App. D at 207.
[18] CARB ISOR, App. D at 67.

102-13 continued from above

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NEVADA CITY, CA 95959
(530)264-7157

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jet in Table 3 establish an 11% crediting disadvantage compared to the diesel benchmark values contained in Table 2. In today's market, this 11% disadvantage translates in economic terms to a $0.16 discount in LCFS credits generated. Thus the production of alternative jet fuel will remain economically disadvantaged in yet another policy program even with the recognized benefit of LCFS program inclusion. 102-3 cont.

It is within this landscape that the technical and policy issues pertaining to carbon intensity and LCFS credit generation should be evaluated. The AJF Producers recognize both the general LCFS principle of fuel neutrality and the importance of RD in fulfilling California's climate and air quality goals. We therefore request a revised CI table for jet fuel that immediately establishes crediting parity between AJF and RD fuel, or moves to crediting parity between the two fuels as quickly as possible.

Thank you for your consideration of our input. Please contact us if any further input would be helpful. We look forward to continuing to provide input to this proceeding.

Sincerely,

Graham Noyes

Exhibit A

OPIS West Coast Spot Market Report

A Daily Report on U.S. West Coast Spot Prices plus News and Commentary

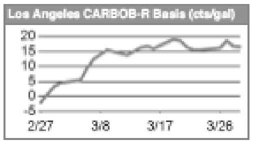
OPIS By IHS Markit

March 29, 2018

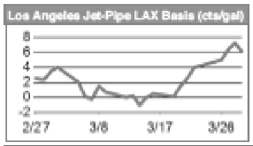
West Coast 30-Day Average Snapshot

Los Angeles CARB No. 2 Basis (cts/gal)

Los Angeles CARBOB-R Basis (cts/gal)



Los Angeles Jet-Pipe LAX Basis (cts/gal)



HOLIDAY NOTICE: U.S. OPIS Spot Reports will not be published on Friday, March 30, in observance of the Good Friday holiday. Publication will resume as normal on Monday, April 2.

SUBSCRIBER NOTICE: As part of our ongoing commitment to ensure our spot market assessments remain relevant, accurate and comprehensive, OPIS is declaring a two-week open-comment period on all of its spot-pricing methodologies. From Friday, March 16, to the close of business Friday, March 30, please direct comments about our spot methodologies to Energy-SpotComplianceGroup@opisnet.com. To review OPIS' existing methodology for its various products and reports, please visit www.opisnet.com/about/methodology.aspx. OPIS' editorial and management team will examine each comment and evaluate whether the feedback ought to result in an alteration, enhancement or clarification of our methodology. Although comments are welcome any time of the year, we will repeat our open-comment period every three months.

PACIFIC NORTHWEST GASOLINE PRICES POP 4CTS/GAL

3/29/2018 - Oil prices ended the first quarter very similar to the way they moved within the confines of the first 88 days of the year, with fairly narrow ranges defining key energy contracts.

May WTI rose 56cts/bbl to $64.94/bbl with June assessed at $64.87/bbl. A reduction in the rig count helped promote some strength, but it might take something more considerable to retake ground above $66/bbl for domestic crude.

Reports from the Midland area suggest that production is outstripping pipeline takeaway capacity, with Midland WTI trading at $3.75/bbl under futures. That has inspired some opportunistic traders to begin looking at rail as a possible solution for a growing bottleneck.

Brent crude was worth $69.36/bbl in June, with the expiring May contract

(Continued on Page 3)

New York Mercantile Exchange at Settlement

WTI Crude Oil ($/bbl)

Month	Price	Change
MAY	64.94	0.56
JUN	64.87	0.52
JUL	64.54	0.48

RBOB Unleaded (cts/gal)

Month	Price	Change
APR	201.79	0.63
MAY	202.08	0.14
JUN	202.50	0.32

ULSD (cts/gal)

Month	Price	Change
APR	202.84	1.36
MAY	202.10	0.71
JUN	201.90	0.74

L.A. 3-2-1 Crack Spread*

Price ($/bbl)	Change
20.11	-0.62

*Crack is based on midpoints for L.A. CARBOB Gasoline, CARB and ANS

Snapshot of OPIS Mean West Coast Prompt Month Spot Pipeline Prices and Basis Differentials (cts/gal)

	Los Angeles				Bay Area				Pacific Northwest			
	Physical Prices		Basis Diff.		Physical Prices		Basis Diff.		Physical Prices		Basis Diff.	
Product	Mean	Change	Mean	Change	Mean	Change	Mean	Change	Mean	Change	Mean	Change
ULS No. 2	210.225	1.085	8.125	0.375	205.100	-0.290	3.000	-1.000	225.850	3.460	23.750	2.750
CARB No. 2	210.225	1.085	8.125	0.375	205.100	-0.290	3.000	-1.000	-- --	-- --	-- --	-- --
Sub-oct Reg	218.080	-0.110	16.000	-0.250	211.080	2.640	9.000	2.500	218.080	4.150	16.000	3.250
Sub-oct Pre	233.580	-0.110	31.500	-0.250	239.080	2.640	37.000	2.500	252.580	4.150	50.500	3.250
CARBOB-R**	218.580	-0.110	16.500	-0.250	214.580	2.640	12.500	2.500	218.080	4.150	16.000	3.250
CARBOB-P**	233.580	-0.110	31.500	-0.250	240.580	2.640	38.500	2.500	252.580	4.150	50.500	3.250
JET **	208.225	-0.415	6.125	-1.125	208.225	-0.415	6.125	-1.125	210.725	-0.415	8.625	-1.125
JET-WTG AVG	208.350	-0.375	6.250	-1.085	-- --	-- --	-- --	-- --	-- --	-- --	-- --	-- --
B5	-- --	-- --	-- --	-- --	-- --	-- --	-- --	-- --	229.850	3.460	27.750	2.750
AZRBOB-R	219.080	-0.110	17.000	-0.250	-- --	-- --	-- --	-- --	-- --	-- --	-- --	-- --
AZRBOB-P	234.080	-0.110	32.000	-0.250	-- --	-- --	-- --	-- --	-- --	-- --	-- --	-- --
CARB RFG-R	213.400	0.095	-- --	-- --	209.800	2.570	-- --	-- --	-- --	-- --	-- --	-- --
CARB RFG-P	226.900	0.095	-- --	-- --	233.200	2.570	-- --	-- --	-- --	-- --	-- --	-- --

Full price display on page 2. Note: **L.A. Jet Fuel is JET Pipe LAX, Bay Area Jet Fuel is JET Pipe, PNW CARBOB-R is Suboctane Reg (FOB Seattle), PNW CARBOB-P is Sub-octane Pre (FOB Seattle).

Exhibit A

OPIS West Coast Spot Market Report

March 29, 2018

OPIS West Coast Prompt Spot Pipeline Prices and Basis Differentials (cts/gal)

Los Angeles

		Physical Prices				Basis Differentials				
Product	Timing	Low	High	Mean	Change	Low	High	Mean	Change	Wt. Avg
ULS NO. 2	APR	209.60	210.85	210.225	1.085	7.50	8.75	8.125	0.375	-- --
CARB No. 2	APR	209.60	210.85	210.225	1.085	7.50	8.75	8.125	0.375	210.495
JET-PipeLAX	APR	208.10	208.35	208.225	-0.415	8.00	8.25	8.125	-1.125	208.350
Sub-Oct Reg 9.0 RVP	APR	217.56	218.56	218.060	-0.110	15.50	16.50	16.000	-0.250	-- --
Sub-Oct Pre 9.0 RVP	APR	233.06	234.06	233.560	-0.110	31.00	32.00	31.500	-0.250	-- --
AZRBOB-R 8.0 RVP	APR	218.56	219.56	219.060	-0.110	16.50	17.50	17.000	-0.250	-- --
AZRBOB-P 8.0 RVP	APR	233.56	234.56	234.060	-0.110	31.50	32.50	32.000	-0.250	-- --
CARBOB-R 5.99 RVP	APR	218.06	219.06	218.560	-0.110	16.00	17.00	16.500	-0.250	218.560
CARBOB-P 5.99 RVP	APR	233.06	234.06	233.560	-0.110	31.00	32.00	31.500	-0.250	-- --
CARB-RFG Reg	APR	212.75	214.05	213.400	0.095	-- --	-- --	-- --	-- --	-- --
CARB-RFG Pre	APR	226.25	227.55	226.900	0.095	-- --	-- --	-- --	-- --	-- --

San Francisco

		Physical Prices				Basis Differentials				
Product	Timing	Low	High	Mean	Change	Low	High	Mean	Change	Wt. Avg
ULS NO. 2	APR	204.60	205.60	205.100	-0.290	2.50	3.50	3.000	-1.000	-- --
CARB No. 2	APR	204.60	205.60	205.100	-0.290	2.50	3.50	3.000	-1.000	205.100
JET-Pipe	APR	208.10	208.35	208.225	-0.415	8.00	8.25	8.125	-1.125	-- --
Sub-Oct Reg 7.8 RVP	APR	210.56	211.56	211.060	2.640	8.50	9.50	9.000	2.500	-- --
Sub-Oct Pre 7.8 RVP	APR	238.56	239.56	239.060	2.640	36.50	37.50	37.000	2.500	-- --
CARBOB-R 5.99 RVP	APR	214.06	215.06	214.560	2.640	12.00	13.00	12.500	2.500	214.560
CARBOB-P 5.99 RVP	APR	240.06	241.06	240.560	2.640	38.00	39.00	38.500	2.500	-- --
CARB-RFG Reg	APR	209.15	210.45	209.800	2.570	-- --	-- --	-- --	-- --	-- --
CARB-RFG Pre	APR	232.55	233.85	233.200	2.570	-- --	-- --	-- --	-- --	-- --

Pacific Northwest

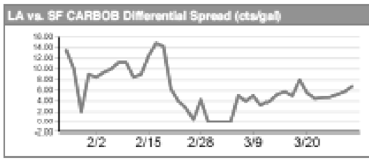
		Physical Prices				Basis Differentials			
Product	Timing	Low	High	Mean	Change	Low	High	Mean	Change
ULS NO. 2	PMT MAR	225.35	226.35	225.850	3.460	23.25	24.25	23.750	2.750
JET-Pipe	PMT MAR	210.60	210.85	210.725	-0.415	8.50	8.75	8.625	-1.125
B5	PMT MAR	229.35	230.35	229.850	3.460	27.25	28.25	27.750	2.750
Sub-Oct Reg 9.0 RVP	PMT MAR	217.56	218.56	218.060	4.150	15.50	16.50	16.000	3.250
Sub-Oct Pre 9.0 RVP	PMT MAR	252.06	253.06	252.560	4.150	50.00	51.00	50.500	3.250
Sub-Oct Reg 13.5 (Seattle)	PMT MAR	217.56	218.56	218.060	4.150	15.50	16.50	16.000	3.250
Sub-Oct Pre 13.5 (Seattle)	PMT MAR	252.06	253.06	252.560	4.150	50.00	51.00	50.500	3.250

Los Angeles Physical Forward Curve Prices

		Physical Prices				Basis Differentials			
Product	Timing	Low	High	Mean	Change	Low	High	Mean	Change
CARBOB-R 5.99 RVP	MAY	211.50	212.50	212.000	-1.180	9.00	10.00	9.500	-1.500
CARBOB-R 5.99 RVP	JUN	208.93	209.93	209.430	0.390	7.00	8.00	7.500	0.000
CARBOB-R 5.99 RVP	JUL	208.84	209.84	209.340	0.470	8.50	9.50	9.000	0.000
CARB No. 2	MAY	208.40	209.40	208.900	1.240	6.50	7.50	7.000	0.500
JET-PipeLAX	MAY	206.40	207.40	206.900	0.740	4.50	5.50	5.000	0.000
JET-PipeLAX	JUN	205.30	206.30	205.800	0.790	3.50	4.50	4.000	0.000

*NOTE: L.A gasoline prices are WEST LINE, and S.F. gasoline prices are NORTH LINE-ZERO LINE. Las Vegas gasoline is represented by L.A. regular sub-octane and premium sub-octane. AZRBOB is the year around gasoline product for Arizona. Pacific Northwest gasoline and No.2 oil prices are FOB Portland Olympic Pipeline; PNW Jet Fuel is FOB Seattle Barge. CARB RFG-R and CARB RFG-P in L.A. and S.F. is not a fungible pipeline product, but a reflection of the value of blending CARBOB with 10% ethanol. Ethanol quotes on page 4 are for ethanol delivered railcar to West Coast locations.

LA vs. SF CARBOB Differential Spread (cts/gal)



LA vs. SF CARB Diesel Differential Spread (cts/gal)

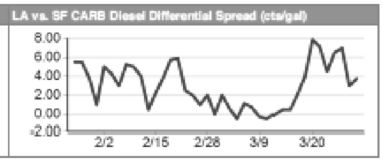


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Exhibit A

OPIS West Coast Spot Market Report

March 29, 2018

L.A. Paper Forward Curve Basis Differential (cts/gal)

Product	Timing	Low	High	Mean	Change
CARBOB	APR	12.50	13.50	13.000	0.500
CARBOB	MAY	9.50	10.50	10.000	0.000
CARBOB	Q2	11.00	12.00	11.500	0.000
CARBOB	Q3	12.00	13.00	12.500	0.000
CARB No. 2	APR	7.00	8.00	7.500	0.000
CARB No. 2	MAY	5.50	6.50	6.000	0.000
CARB No. 2	Q2	5.50	6.50	6.000	0.000
JET-PipeLAX	APR	5.25	6.25	5.750	-0.250
JET-PipeLAX	MAY	2.50	3.50	3.000	-1.250
JET-PipeLAX	Q2	3.00	4.00	3.500	0.000

PADD 5 EIA Inventory - Week Ending 03/23

Location	This Week	Last Week	Last Year	Week Change	Year Change
Gasoline	32,663	32,756	29,231	-93	3,432
No. 2 Oil	12,405	12,711	13,791	-306	-1,386
ULSD < 15ppm	11,397	11,785	12,499	-388	-1,102
Kerosene Jet	10,457	10,993	9,082	-536	1,375
Residual Fuel	5,114	4,737	4,648	377	466
Crude Oil	51,219	48,389	57,522	2,830	-6,303
Crude Input	2,593	2,536	2,434	57	159

Note: Inventory levels are in thousands of barrels

California CEC Inventory - Week Ending 03/23

Location	This Week	Last Week	Last Year	Week Change	Year Change
CARB RFG	7,587	8,048	6,055	-461	1,532
Non-Calif. Gasoline	1,350	1,080	1,570	270	-220
Gasoline Blend. Components	5,644	5,634	5,780	10	-136
CARB-Diesel	1,957	1,877	2,433	80	-476
Other Diesel	1,277	1,534	1,075	-257	202
Kerosene Jet	3,669	3,739	3,006	-70	663
Crude Oil	15,653	15,495	16,921	158	-1,268
Crude Input	12,667	12,355	12,536	312	131

Note: Inventory levels are in thousands of barrels

PADD 5 EIA Gasoline Inventories - 12 Week Trend (thousand bbl)

PADD 5 EIA Distillate Inventories - 12 Week Trend (thousand bbl)

remaining around $70.22/bbl. There is definitely a perception that Brent may outperform WTI in April.

Gasoline saw modest increases in most spot markets, with April RBOB settling up 0.63cts/gal at $2.0179/gal while May added 0.14cts/gal to $2.0206/gal. The first quarter was an active one for refinery maintenance, but "events" or disruptions at refineries were rare. Cash prices are well above futures on the West Coast, but the key market is undoubtedly the U.S. Gulf Coast. If robust exports are maintained or increased in April, the 2017 highs for prompt RBOB may fall.

Diesel rallied slightly, with April settling at $2.0284/gal, up 1.36cts/gal while May rose 0.71cts/gal to $2.021/gal. There isn't much excitement in cash diesel markets, but there is a sense that very ample exports will continue to make for an interesting off-season.

--Tom Kloza, tkloza@opisnet.com

SOUTHERN CALIFORNIA GAS FIRM TO AID ACCELERATION OF DIESEL-TO-GAS CONVERSION FOR TRUCKS

Southern California Gas Co., which says it's the largest natural distribution utility in the U.S., said it is helping California fleets get more drivers behind the wheels of new near-zero emissions heavy-duty natural gas trucks.

The effort is part of a $21 million Prop 1B incentive pool administered by the South Coast Air Quality Management District (SCAQMD). SoCalGas representatives provided assistance on 400 Prop 1B applications throughout its service territory.

If all these applications are accepted and receive funding, SoCalGas customers will replace at least 400 diesel trucks with near-zero natural gas trucks. That's the equivalent of taking more than 22,000 passenger cars off the road, SoCalGas said.

The Prop 1B Program is intended to reduce diesel air pollution from goods movement operations and achieve the earliest possible health risk reduction, SoCalGas said. Fleet owners seeking to replace diesel trucks may be eligible for up to $100,000 toward the purchase of a new natural gas truck.

For the SCAQMD solicitation, SoCalGas customers submitted more than 150 applications, with many of these requests coming from fleets smaller than 10 trucks, the utility said. When these near-zero natural gas trucks are fueled by renewable natural gas, greenhouse gas (GHG) emissions are reduced by 80%, it said. Already, 60% of natural gas fleets in California are fueled with renewable natural gas and this number is expected to climb to about 90% by the end of this year, SoCalGas said.

The SCAQMD solicitation is one of many incentive programs SoCalGas customers used in 2017. More than 225 applications were submitted to the San Joaquin Valley Air Pollution Control District and San Diego Air Pollution Control District from SoCalGas customers. This demand far exceeded the $14 million in available incentive funding, SoCalGas said.

The transportation sector is responsible for about 40% of California's GHG emissions and more than 80% of the state's NOx, or smog-forming, emissions, the company said.

While the current Prop 1B pool solicitation is now closed, there is another incentive pool available through the SCAQMD, SoCalGas said. The Carl Moyer incentive program is open to fleets that operate in Los Angeles, Orange and Riverside counties from now until June 5. Additionally, the San Joaquin Valley Air Pollution Control District recently established a new grant incentive option for its Truck Voucher Program that would replace existing heavy-duty trucks with the cleanest, ultra-low NOx 12-Liter truck available.

--Edgar Ang, eang@opisnet.com

(Continued on Page 4)

Exhibit A

OPIS West Coast Spot Market Report

March 29, 2018

OPIS Spot Feedstocks

Product	Range (cts/gal) Low	Range (cts/gal) High	Diff to 70/30 (cts/gal) Low	Diff to 70/30 (cts/gal) High	Diff to WTI ($/bbl) Low	Diff to WTI ($/bbl) High	Diff to ANS ($/bbl) Low	Diff to ANS ($/bbl) High
Low Sulfur VGO	211.05	213.05	-5.00	-3.00	23.70	24.55	18.10	18.95
High Sulfur VGO	207.05	209.05	-9.00	-7.00	22.00	22.85	16.45	17.30
Light Cycle Oil	171.40	173.40	-38.85	-36.85	2.50	3.25	-- --	-- --

OPIS Spot NGL (cts/gal)

Market	Date	Propane Low	Propane High	N.Butane Low	N.Butane High	Butane Mix Low	Butane Mix High	Isobutane Low	Isobutane High	N. Gasoline Low	N. Gasoline High
Delivered LA Basin	3/29	121.75	129.75	106.63	107.13	106.63	107.13	117.63	118.13	-- --	-- --
Delivered Bakersfield	3/29	124.75	131.75	106.63	107.13	106.63	107.13	-- --	-- --	135.13	139.88
Delivered Bay Area	3/29	117.25	118.25	106.63	107.13	106.63	107.13	117.63	118.13	-- --	-- --

WC/WTI-NYMEX/Atlantic Basin Crude Values ($/bbl)

Product	Low	High	Last	Change
Alaska North Slope	70.27	70.77	70.52	0.74
Line 63	66.27	66.77	66.52	0.74
THUMS	59.21	59.71	59.46	-0.77

Product	Low	High	Last	Change
SJV	58.46	58.96	58.71	-0.77
WTI	64.16	65.26	64.94	0.58
Brent	69.10	70.44	70.27	0.74

U.S. West Coast Crude Oil Postings ($/bbl)

Location	API	Chev	API	PMTC	API	MOBIL
Buena Vista	26.0	69.34	26.0	66.42	26.0	70.14
Hunt. Beach	-- --	-- --	20.0	61.06	-- --	-- --
Kern River	-- --	-- --	13.0	58.06	-- --	-- --
Long Beach	-- --	-- --	27.0	64.51	-- --	-- --
Midway Sunset	13.0	64.79	13.0	61.56	13.0	65.46
Wilmington	-- --	-- --	17.0	58.81	-- --	-- --
Effective Date		03/28		03/28		03/28

Location	API	STUSCO	API	UNION 76
Buena Vista	26.0	69.40	26.0	65.20
Midway Sunset	13.0	64.86	13.0	59.90
Effective Date		03/28		03/28

Today's Closing Singapore Prompt Jet Kerosene Prices

Market	Low	High	Mean	Change
FOB Singapore ($/bbl)	81.92	82.02	81.97	0.190

OPIS Ethanol Prices (cts/gal)

Market	Timing	Low	High	Mean	Change
LA CI 79.90	PROMPT	165.00	169.00	167.000	2.000
LA CI 79.90	ANY	165.00	169.00	167.000	2.000
SF CI 79.90	PROMPT	165.00	169.00	167.000	2.000
SF CI 79.90	ANY	165.00	169.00	167.000	2.000
Oregon CI 69.89	PROMPT	159.00	162.00	160.500	1.500
Washington Eth.	PROMPT	157.00	160.00	158.500	1.500
Phoenix Eth.	PROMPT	158.00	162.00	160.000	5.500

OPIS California Low Carbon Fuel Standard

Product	Low	High	Mean	Change
Carbon Credit ($/MT)	140.000	145.000	142.5000	1.0000
CI Pts Ethanol ($/CI)	0.01141	0.01182	0.011615	0.000080
CI Pts Biodiesel ($/CI)	0.01766	0.01829	0.017975	0.000125
Carbon CPG Diesel (cts/gal)	6.72	6.96	6.840	0.050
Carbon CPG Del 95% (cts/gal)	6.38	6.61	6.495	0.045
Carbon CPG Gasoline (cts/gal)	10.43	10.80	10.615	0.075
Carbon CPG Gas 90% (cts/gal)	9.38	9.72	9.550	0.070

OPIS U.S. RIN Values (cts/RIN)

Product	Year	Low	High	Mean	Change
Corn Ethanol	2017	41.50	44.50	43.000	1.500
Corn Ethanol	2018	43.00	46.00	44.500	0.500
Biodiesel	2017	56.50	60.50	58.500	-1.500
Biodiesel	2018	64.00	68.00	66.000	-1.750
Cellulosic	2017	255.00	261.00	258.000	0.000
Cellulosic	2018	247.00	253.00	250.000	0.000
Adv. Biofuel	2017	55.50	59.50	57.500	-1.500
Adv. Biofuel	2018	63.00	67.00	65.000	-1.750

PG&E TO OFFER 66,000 LCFS CREDITS IN AUCTION

California investor-owned utility Pacific Gas and Electric (PG&E) on Thursday said that it plans to auction on Friday approximately 66,000 California Low Carbon Fuel Standard (LCFS) credits generated from the sale of electricity for electric-vehicle fueling and compressed natural gas as a vehicular fuel.

The utility said bidders must notify the utility by 10 a.m. PT tomorrow whether they intend to participate and execute PG&E's LEAP Master Agreement for buying and selling LCFS credits.

PG&E said it plans to notify winning buyers no later than 1 p.m. PT Friday.

PG&E's minimum bid quantity is 1,000 credits. Bidders must submit both quantity and price in their bids. PG&E said it reserves the right to award partial bid quantities. A weighted average of winning bids for cleared quantities will be used to calculate the transaction price.

LCFS credit prices have steadily increased for much of the past week. They were reported in the range of $142-$145/credit early Thursday after being assessed by OPIS at $141.50/credit on Wednesday.

OPIS on Feb. 14 assessed the LCFS credit at an all-time high of $151.50/credit, but the assessment dipped to a 2018 low of $111/credit on Feb. 27. Prices have since rebounded, with Wednesday's assessment holding $21/credit above the month-ago level.

--Jordan Godwin, jgodwin@opisnet.com

WEST COAST REFINED PRODUCTS LOGIC:

L.A. CARBOB-R 5.99 RVP: April prompt was assessed at NYMEX May RBOB contract plus 16.5cts/gal, based on a trade at that level.

L.A. CARB No. 2: April prompt was assessed at the NYMEX May ULSD contract plus 8.125cts/gal, based on trades at plus 7.5cts/gal to plus 8.75cts/gal.

L.A. ULS No. 2: April prompt was assessed at the NYMEX May ULSD contract plus 8.125cts/gal, based on a flat regrade relationship to L.A. CARB No. 2.

L.A. JET-Pipe LAX: April prompt was assessed at the NYMEX May ULSD contract plus 6.125cts/gal, based on a trade at plus 6.25cts/gal and a subsequent offer at plus 6cts/gal.

S.F. CARBOB-R 5.99 RVP: April prompt was assessed at the

(Continued on Page 5)

Exhibit A

Calif. Carbon Allowance Assessments ($/mt)

Vintage	Timing	Low	High	Mean
Previous Yr.	PMT APR '18	14.71	14.73	14.720
Previous Yr.	FWD DEC '18	15.08	15.10	15.090
Current Yr.	PMT APR '18	14.67	14.69	14.680
Current Yr.	FWD DEC '18	15.07	15.09	15.080
Next Yr.	PMT APR '18	14.65	14.67	14.660
Next Yr.	FWD DEC '18	15.05	15.07	15.060

Prompt Calif. Cap-at-the-Rack Prices (cts/gal)

Product	Price	Wk Avg	30-Day Avg
Summer CARB RFG-R	11.83	11.848	11.881
Summer CARB RFG-M	11.80	11.818	11.852
Summer CARB RFG-P	11.79	11.808	11.842
Winter CARB RFG-R	11.80	11.818	11.858
Winter CARB RFG-M	11.80	11.818	11.858
Winter CARB RFG-P	11.82	11.834	11.871
CARB No.2	15.03	15.052	15.099
B5 Biodiesel	14.28	14.302	14.347
Propane	8.25	8.262	8.286
LNG (cts/DGE)	10.75	10.762	10.798

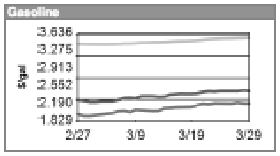
Today's Spot-to-Rack-to-Retail Snapshot

Gasoline ($/gal)	Price	Change
Basket of Racks	2.450	-0.010
Retail Average	3.538	0.008
L.A. CARBOB-R	2.188	-0.001

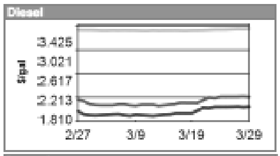
Diesel ($/gal)	Price	Change
Basket of Racks	2.307	-0.009
Retail Average	3.729	0.007
L.A. CARB No. 2	2.102	0.011

30-Day Spot-to-Rack-to-Retail Trend

Gasoline



Diesel



Legend

L.A. CARBOB-R — Basket of Racks

L.A. CARB No. 2 — Retail Average

NOTE: The methodology for the Rack-to-Retail Trend Snapshot can be found at http://www.opisnet.com/about/methodology.aspx.

NYMEX May RBOB contract plus 12.5cts/gal, based on a trade at L.A. CARBOB-R minus 4cts/gal.

S.F. CARB No. 2: April prompt was assessed at the NYMEX May ULSD contract plus 3ct/gal, based on bids at plus 3cts/gal and offers at plus 3cts/gal, with differing volumes.

PNW SUB-OCT Reg 9.0 RVP: March prompt was assessed at the NYMEX May RBOB contract plus 16cts/gal, based on a trade at that level.

PNW ULS No. 2: March prompt was assessed at the NYMEX May ULSD contract plus 23.75cts/gal, based on a trade at plus 23cts/gal versus the NYMEX April ULSD contract.

WEST COAST REFINED PRODUCTS ANALYSIS:

The Pacific Northwest gasoline market saw robust price gains Thursday after the prompt market began trading against the NYMEX May RBOB contract. Sub-octane cash differentials increased 3.25cts/gal to trade at the Merc plus 16cts/gal, boosting outright prices to $2.1806/gal.

Similarly the PNW ultra-low-sulfur diesel fuel market stepped higher on a single trade. Prompt market cash differentials shot up 2.75cts/gal to a 23.75cts/gal premium to the NYMEX May ULSD contract following a trade at the April contract plus 23cts/gal. It's rare to see the PNW market reference a near expiry NYMEX contract particularly when the majority of the industry had previously decided to reference the next month contract, which is less prone to volatile prices swings. PNW ULSD flat price close the day up about 3.5cts/gal at $2.2585/gal.

Cash differentials for Los Angeles CARBOB were narrowly changed, edging just 0.25cts/gal lower following a trade at the NYMEX May RBOB contract plus 16.5cts/gal. The Southern California spot market has been trading in the mid-to- high teens over the past three weeks with demand heightened in response to abundant turnaround activity and some process hiccups.

Industry sources noted that a bit of trader length remained for the April L.A. CARBOB market, but that dynamic has yet to put any notable downward pressure on spot activity. Outright prices eased back with the light spot market dip to close at $2.1856/gal.

The San Francisco CARBOB market traded at a 4cts/gal discount to L.A. CARBOB, narrowing the N/S price spread.

The L.A. CARB diesel fuel spot market saw a range of trading over demand for different clip volumes. April prompt barrels traded at between the Merc plus 7.5cts/gal and plus 8.75cts/gal, seeing diffs firm up a tad during the session. S.F. CARB diesel fuel cash differentials eased a penny to 3cts/gal above the May ULSD contract, with bids and offers heard at that level, but counterparties couldn't get on the same page about volume.

L.A. jet fuel cash differentials traded at the Merc plus 6.25cts/gal and was later heard offered at plus 6cts/gal in the afternoon session, with no additional trades confirmed. Flat prices were down about a half cent at $2.08225/gal.

--Lisa Street, lstreet@opisnet.com

OPIS WEST COAST FUEL SUPPLY & TRANSPORTATION OPPORTUNITIES: Anyone doing business in the oil sector on the West coast knows it is uniquely regulated and difficult to navigate. Learn from the experts who have immersed themselves and have deep roots in this market. OPIS has assembled a panel of market pros to educate you on the ins and outs of what it takes to increase market share and profitability in the West coast fuel market. Then, spend the day networking over golf or a wine and olive oil tasting with newfound business partners and other peers attending this not-to-be-missed event. Learn more: https://www.opisnet.com/west-coast-fuel-supply

Exhibit A

OPIS West Coast Spot Market Deal Log

Los Angeles

Product	Timing	Differential	Reference	kbbl	Notes
CARBOB Regular 5.99 RVP Prompt	APR	+16.50	May RBOB	25	
CARB No2 Prompt	APR	+8.50	May No2	25	
CARB No2 Prompt	APR	+8.75	May No2	10	
CARB No2 Prompt	APR	+8.50	May No2	25	
CARB No2 Prompt	APR	+7.50	May No2	10	
Jet LAX Prompt	APR	+8.25	May No2	25	

San Francisco

Product	Timing	Differential	Reference	kbbl	Notes
CARBOB Regular 5.99 RVP Prompt	APR	-4.00	LA CARBOB Regular 5.99 RVP	50	S.F. under L.A.

Pacific Northwest

Product	Timing	Differential	Reference	kbbl	Notes
Sub-Octane Unleaded 9.0 RVP Prompt	PMT MAR	+18.00	May RBOB	10	
ULS No2 Prompt	PMT MAR	+23.00	Apr No2	5	

Los Angeles Paper

Product	Timing	Differential	Reference	kbbl	Notes
Jet LAX Prompt	APR	+8.25	May No2	50	
Jet LAX Other	MAY	+3.00	Jun No2	25	
Jet LAX Prompt	APR	+6.00	May No2	50	
Jet LAX Other	MAY	+3.00	Jun No2	25	
Jet LAX Prompt	APR	+5.50	May No2	25	
Jet LAX Other	MAY	+3.00	Jun No2	25	
Jet LAX Prompt	APR	+5.50	May No2	25	
Jet LAX Prompt	APR	+5.25	May No2	50	
Jet LAX Prompt	APR	+5.75	May No2	25	
Jet LAX Prompt	APR	+5.50	May No2	25	

Exhibit A

OPIS West Coast Spot Market Report

March 29, 2018

U.S. West Coast Price Discovery Methodology

Editors confirm and record deals done for gasoline and distillate products with a minimum pipeline size of 10,000 bbl in California and 5,000 bbl in the Pacific Northwest. As the majority of the market is done on an EFP basis, we follow deals as basis discounts or premiums to the New York Mercantile Exchange. We consider fixed-price deals only if they fall within the full-day differential range based off the NYMEX at settlement. Fixed price deals in California spot markets are converted to an EFP when reported and confirmed and then reapplied to the NYMEX settlement price.

OPIS does publish "prompt" ranges, which are trades that reflect "any month / buyers option" transactions. "Buyers option" gives the buyer the choice of taking delivery in any of the four cycles in throughout the month. In Los Angeles, OPIS identifies the prompt Kinder Morgan cycle for timing clarity but ranges are buyer option/any month lifting.

OPIS works with the Kinder Morgan Pipeline to determine the timing of the various cycles throughout the month. Typically, each month has four pumping cycles. In cases where it is close to the end of the months trading cycle, OPIS reserves the right to roll coverage forward to the more liquid month.

For the Los Angeles market, OPIS follows the Kinder Morgan West Line, and in the Bay area the OPIS assessment is for the Kinder Morgan Zero Line. In the Pacific Northwest, prices are FOB Portland - Olympic Pipeline and jet fuel is FOB Seattle barge. For complete methodology, visit http://www.opisnet.com/about/methodology.aspx

Global Head - Energy Analysis:
Tom Kloza
732.730.2558
ICE IM: tkloza
tkloza@opisnet.com

Director - Data, Pricing & Info:
Ben Brockwell
+1 732.730.2519
ICE IM: bbrockwell1
bbrockwell@opisnet.com

VP - Content:
Robert Gough
+1 301.284.2138
ICE IM: rgough
rgough@opisnet.com

Director- Refined Products:
Jennifer Brumback
+1 727.202.6501
ICE IM: jbrumback2
jbrumback@opisnet.com

Managing Editor - West Coast and Carbon:
Lisa Street
+1 832.679.7225
ICE IM: lstreet2
lstreet@opisnet.com

Managing Editor - Northeast and Gulf Coast:
Carly John
+1 301.284.2114
ICE IM: cwright9
cjohn@opisnet.com

West Coast:
Frank Tang
+1 917.455.0926
ICE IM: ftang
ftang@opisnet.com

Kylee West
+1 301.284.2106
ICE IM: kwest
kwest@opisnet.com

Carbon Markets:
Bridget Hunsucker
+1 832.679.7163
ICE IM: bhunsucker1
bhunsucker@opisnet.com

Midwest:
Bayan Raji
+1 832.679.7227
ICE IM: braji1
braji@opisnet.com

Ethanol/Biodiesel:
Spencer Kelly
+1 301.284.2022
ICE IM: skelly15
skelly@opisnet.com

Asian Products:
Jiwon Chung
(65.63)373.519
ICE IM: jchung8
jchung@opisnet.com

Gulf Coast:
Cory Wilchek
+1 301.284.2110
ICE IM: cwilchek
cwilchek@opisnet.com

Andrew Atwal
+1 301.284.1961
ICE IM: aatwal
aatwal@opisnet.com

European Products:
Paddy Gourley
(75) 95117236
ICE IM: paddygourley
pgourley@opisnet.com

Northeast:
Rachel Stroud-Goodrich
+1 301.284.2190
ICE IM: rstroudgoodrich
rstroud-goodrich@opisnet.com

Market News Coverage:
Denton Cinquegrana
Edgar Ang
Beth Heinsohn
Brad Addington
Rajesh Joshi
Jeff Barber
Jordan Godwin

ANY QUESTIONS ABOUT THIS REPORT, CALL LISA STREET AT 832-679-7225. COVERAGE FOR WEEK OF 3/26: 3/26-27: FRANK TANG; 3/28-29 LISA STREET

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RCM
INTERNATIONAL, LLC

P.O. Box 4716, Berkeley, CA 94704
Phone (510) 834-4568
Fax (510) 834-4529
contact@rcmdigesters.com
www.RCMInternationalllc.com

April 19, 2018
Richard Corey
Executive Director

Subject: Amendments to California Low Carbon Fuel Standard

Dear California Air Resources Board,

Currently the LCFS allows for credits for Renewable Power to be applied for hydrogen and electric vehicles for generation in California. We understand the objectives of limiting this opportunity to zero emission transportation options. However, we would also like ARB to consider the opportunity for transmitting manure by wire. Many ethanol producers ship distiller's grains to feed lots and have the opportunity to potentially truck manure back to a digester at the ethanol plant which would avoid methane emissions and also provide a source of low-carbon biogas for the ethanol plant.

However, the logistics of hauling manure and dealing with the digestate the ethanol plant are a challenging obstacle. Manure could be converted to biogas at the feedlot or dairy; however, the biogas is also not readily transported to an ethanol plant unless it is very close by which is rarely the situation. The final option would be to convert the manure to biogas and then to electric power for use at the ethanol plant and transmit the power via the electric grid. 114-1

We recognize that the LCFS currently does not allow for this option however the alternative would be to haul the manure by truck which would create more greenhouse gas emissions and additional road traffic as well as diesel exhaust emissions. We are open to discussing the potential options for transmitting manure by wire.

Perhaps the ARB could require new digester and power projects for this approach to eliminate providing credits for activities that already exist. Thank you for considering this important options for reducing GHG emissions.

Sincerely,

Mark Moser

P.O. Box 4716, Berkeley, CA, 94704 Phone (510) 834-4568 Fax (510) 834-4529

Comment Log Display

OP_NEXTGEN1_124

Below is the comment you selected to display.
Comment 124 for LCFS 2018 (lcfs18) - 45 Day.

First Name: Colin
Last Name: Murphy
Email Address: colin.murphy@nextgenpolicy.org
Affiliation: NextGen Policy Center

Subject: Update to LCFS report on docket
Comment:

Please find attached NextGen's comment on the proposed rulemaking, completed Illustrative Compliance Scenario Calculators for our suggested 23% and 24% 2030 CI targets, an updated version of the Cerulogy Research Report "California's Clean Fuel Future" and two memos which are cited appendices to the report.

Note that this version of the report supersedes the version from the previous comment, which we have asked the clerk of the board to withdraw.

Attachment: www.arb.ca.gov/lists/com-attach/145-lcfs18-AG4FZlwlUHdQMQRh.zip

Original File Name: NextGen Submission.zip

Date and Time Comment Was Submitted: 2018-04-23 16:56:16

OP_NEXTGEN1_124

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April 23, 2018

Chair Mary Nichols
California Air Resources Board
1001 I Street
Sacramento CA, 95814

RE: Rulemaking to amend and re-adopt the Low Carbon Fuel Standard

Dear Chair Nichols,

Thank you for the opportunity to comment on the present rulemaking to amend and re-adopt California's Low Carbon Fuel Standard (LCFS). The LCFS is a key element of California's climate and clean energy leadership. AB 32 (Chapter 488, Statutes of 2006) began the process of decarbonizing one of the world's largest and most advanced economies. The success of policies such as the LCFS will likely allow California to meet AB 32's goal of returning to 1990 levels of emissions well before the 2020 target date. With the passage of SB 32 (Chapter 249, Statutes of 2016), California has set an ambitious, but achievable, target of reducing emissions 40% below 1990 levels by 2030. 124-1

Just as the LCFS was important to the success of AB 32, it will play an even more crucial role as the state works to attain the SB 32 target and set a course for even deeper cuts after 2030. California has achieved most of its emission reductions to date from the electricity sector and is on track to virtually eliminate emissions from power plants by midcentury; now California must rapidly accelerate emission reduction from the transportation sector to meet its 2030 target and longer term climate goals. It is therefore crucial that the program be re-adopted and positioned to achieve the fullest extent of its potential to drive down emissions and support advanced clean energy technologies.

The LCFS can build upon its track record of success. It has reduced carbon pollution emissions by more than 33 million tonnes since 2011,[1] by incentivizing fuel providers to reduce the carbon intensity of their fuels, blend in lower carbon alternatives or support the deployment of advanced new fuels through LCFS credits. The emphasis on clean transportation has supported over 300 California companies, employing more than 20,000

[1] https://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm

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workers and resulted in over $2 billion of investment in clean fuel production and distribution infrastructure.[2] By displacing highly-polluting petroleum fuels with cleaner alternatives, the LCFS has contributed to California's progress towards healthier air, saving over $1 billion in health care expenditure and reducing the terrible burden asthma, heart disease and lung cancer inflict on Californians.[3] The LCFS is supported by a broad and diverse coalition of California business, scientific, health and community stakeholders who recognize the unique value it provides.[4]

124-2 continues in footnote below

The LCFS must play an even more important role in the next decade of California's climate policy. While California has taken great steps to reduce its emissions of carbon pollution, more is necessary if we are to bring our economy onto a trajectory compatible with preventing catastrophic climate change, as called for in the Paris Accord and the Under 2 MoU.Transportation represents the largest source of emissions in California, with 39% of total in-state anthropogenic emissions coming from vehicles and almost 10% more resulting from the production of transportation fuels.[5] On-road transportation (passenger vehicles and freight trucks) consume the overwhelming majority of transportation fuel. State and Federal policies are working to make vehicles more efficient and provide alternatives to conventional on-road transportation, but these measures cannot, by themselves, deliver sufficient reductions from the transportation sector to meet SB 32 goals. We must decarbonize the fuels which supply our transportation system in addition to consuming less of them.

124-3 continues to footnote below and next page

The LCFS is even more important over the coming decade because it represents one of the only measures by which the state can support emissions reductions in the refinery sector, which accounts for over 45% of industrial emissions or almost 11% of the state total. AB 398 (Chapter 135, Statutes of 2017) authorizes the extension of several key carbon pollution reduction policies, but categorically excludes oil production and refining from direct regulation. It also extends highly preferential treatment under the Industrial Assistance provisions of the Cap and Trade program. The LCFS, through existing and proposed provisions relating to refinery investments, carbon capture and sequestration, innovative crude production and renewable hydrogen,

[2] http://www.calstart.org/Libraries/Policy_Documents/California_s_Clean_Transportation_Technology_Industry_-_2016.sflb.ashx

[3] https://www.edf.org/sites/default/files/content/edf_driving_california_forward.pdf

[4] We note that NextGen joined a group of stakeholders from the California Delivers Coalition on a letter of support for the re-adoption of the LCFS at a higher CI target than staff's original proposal. The provisions of that letter and this one are entirely compatible.

124-2 continued from above

[5] https://www.arb.ca.gov/cc/inventory/data/data.htm

124-3 continued from above

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can drive reductions in this sector. Achieving 40% reductions in carbon pollution by 2030 will be much more difficult if the refining sector does not reduce its emissions to keep pace with the economy as a whole. The LCFS is now the best tool at California's disposal to ensure that the refinery sector makes the investments to do its part. 124-3 cont.

NextGen has been an active participant in the extensive pre-rulemaking workshops and we commend CARB and staff for their strong science-based analysis, commitment to transparency, timely posting of relevant materials and willingness to engage in thoughtful, substantive discussion. Our comment letter reflects several months of extensive engagement on the full scope of issues related to this rulemaking. This letter will begin by addressing the issue of greatest importance in this rulemaking, the selection of 2030 carbon intensity (CI) targets and then move through a variety of other issues on which CARB has asked for stakeholder input.

In general, NextGen **strongly supports the re-adoption of the Low Carbon Fuel Standard through 2030**, with an increased CI reduction target. For the most part, we find the analysis presented by the LCFS team to be extremely high-quality and compelling. Except where noted in this letter, we support re-adoption of the LCFS consistent with the Draft ISOR and proposed regulatory text.

The LCFS Should Be Re-Adopted With A 2030 CI Reduction Target No Lower Than 23% 124-5

Staff have proposed that the LCFS be re-adopted with CI reduction targets increasing by 1.25% per year from 2019 through 2030, to arrive at a 20% CI reduction target by 2030. We feel that this proposal is, in general, an improvement on the trajectory described in pre-rulemaking workshops, which proposed a maximum CI reduction target of 18%, with a rapid ramp up to 2020 followed by several years of static targets before resuming target increases. We think that the proposed target trajectory can be improved upon however.

NextGen urges the Board to instruct staff to develop one or more proposals for more rapid increases in the CI target, for the Board to consider prior to its second vote later this year. These proposals should Recent analysis, which will be discussed in the following section, indicates that there is ample fuel capacity to support a significantly higher reduction target, which would support investment in innovative clean technologies and prevent millions of additional tonnes of carbon pollution from entering the atmosphere. The

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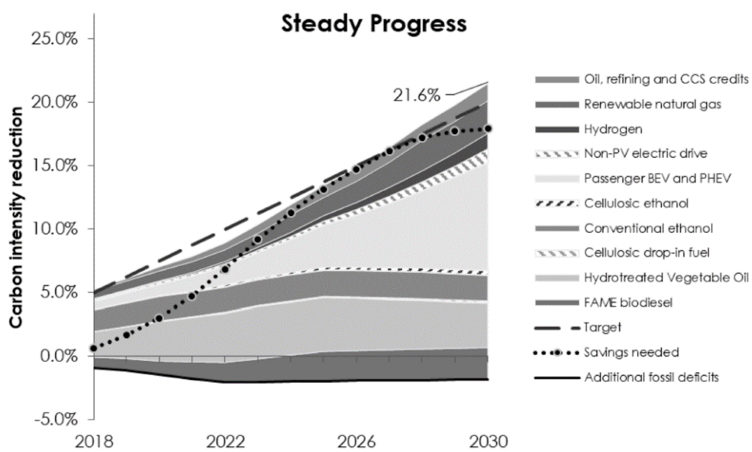
Board must take action now to begin the process of evaluating and adopting a more appropriate CI target for 2030.

California's Clean Fuel Future

This recommendation is based on the research report *California's Clean Fuel Future, Updated: Assessing Achievable Fuel Carbon Intensity Reductions Through 2030,* by Dr. Chris Malins of Cerulogy, sponsored by NextGen, Ceres and the Union of Concerned Scientists.[6] This report evaluates likely low carbon fuel development under a variety of reasonable technological and market conditions over the next twelve years to assess potential supplies of low-carbon fuel and LCFS credits. The report concludes that under moderate assumptions, there are ample supplies of fuel to support a 2030 CI target significantly higher than the 20% proposed by staff.

124-5 Cont.



The *Steady Progress* scenario reflects assumptions about fuel pathway development that are in the moderate part of the potential range of outcomes for each fuel. It assumes that existing state policies continue to develop as planned, but does not assume any significant Federal or State policy actions, nor any transformational market shifts towards clean energy or fuels.

[6] Available at: nextgenamerica.org/californias-clean-fuel-future/

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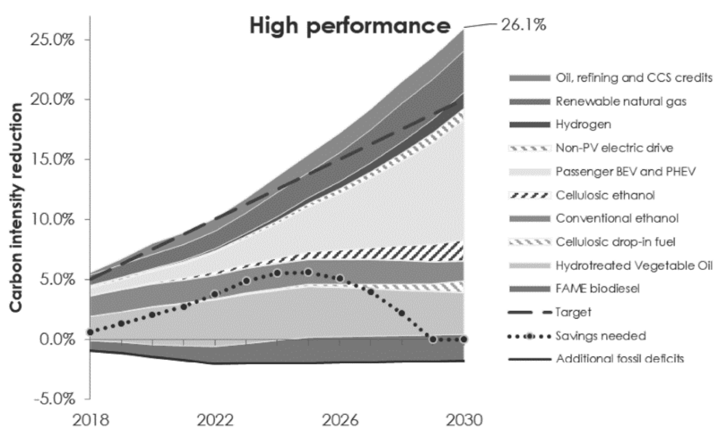
The *Steady Progress* scenario differs from the scenarios modeled by Staff in the illustrative compliance scenario calculator in several key ways. It assumes that the state will meet the Zero-Emission Vehicle (ZEV) deployment target of 5 million vehicles, set by Governor Brown in Executive Order B-48-18. It also assumes slightly greater utilization of new LCFS credit generation pathways relating to investments in clean refineries, and a slightly faster decarbonization of the California electricity grid based on recent projections in the IEPR.

Given California's commitment to clean fuels and transportation, CARB's broad authority to adopt policy under SB 32 and other statutes, and the history of rapid development in the clean transportation sector over the last two decades, we think that the *Steady Progress* scenario represents the lower limit of state ambition. It is, essentially, the least California could do to reduce emissions and clean up transportation. We anticipate that California will continue its leadership in both technological development and climate policy. The State Legislature has made a strong and durable commitment to clean transportation as a major recipient of funding from the Greenhouse Gas Reduction Fund and there have been dozens of bills in the last several Legislative sessions aimed at furthering the deployment of clean vehicles and fuels. Consumers are becoming more aware of, and more interested in, alternatives to petroleum-fueled transportation. Accordingly, the deployment trajectory of key clean transportation technologies are likely to exceed those reflected in the *Steady Progress* scenario. 124-5 cont.



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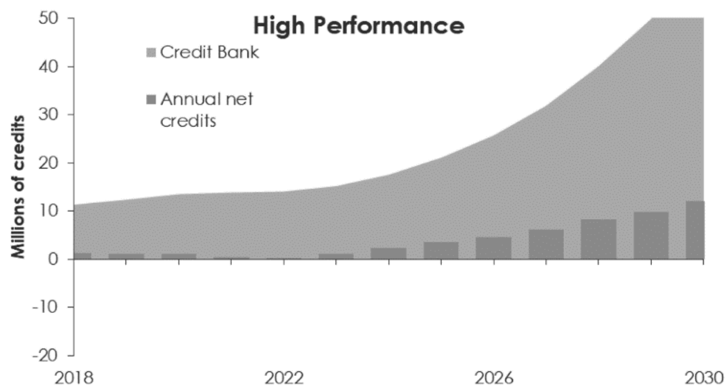
NextGen believes that the *High Performance* scenario better reflects what California can reasonable achieve in the next decade. This scenario reflects more rapid deployment of some technologies, notably a total of 5.8 million ZEVs by 2030 and greater deployment of electric and renewable natural gas vehicles in the medium and heavy duty sectors. Under a 20% target, the technology deployment modeled by the *High Performance* pathway massively over-performs LCFS requirements. This would results in a massive bank of credits accumulating by 2027, which would likely drive LCFS credit prices significantly downward and stifle ongoing investment that would be necessary to attain post-2030 goals (See Figure, below).



124-5 cont.

We note that the *High Performance* scenario is still far more conservative than the maximum technical potential across all low carbon fuel pathways. For example, the the assumption of 5.8 million ZEVs by 2030 is based on a bounding scenario developed by the California Energy Commission, but is lower than the 7 million ZEVs assumed by Southern California Edison in its Deep Decarbonization Scenario or similar ZEV deployment trajectories modeled by Bloomberg New Energy Finance or Navigant, which were cited in the recently adopted Scoping Plan. The *High Performance* scenario also assumes minimal credit generation from electric medium and heavy duty vehicles prior to 2024; recent commitments by major transit agencies to procure electric buses will likely yield more MD/HD electrification credit than this scenario assumes, by themselves. The *High Performance* scenario also assumes significantly lower consumption of alternative distillates, such as renewable diesel and renewable jet fuel, than any of Staff's scenarios with a 20% or higher CI target. We also note that the *High Performance* scenario assumes a modest contribution from carbon capture and sequestration, of around 1.5 million tonnes of carbon dioxide between refineries and conventional ethanol

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facilities in 2030. More significant deployment is quite feasible under likely credit prices through the next decade, which would result in significantly more credit generation than is modeled here.

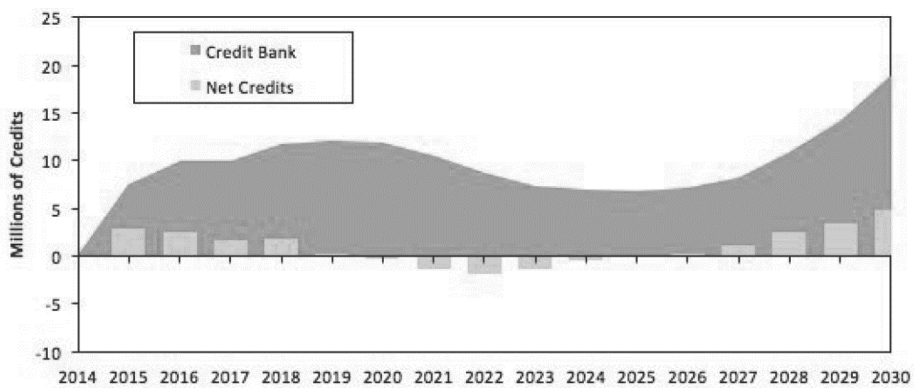
The Rationale for a 23% Target

NextGen is submitting our projection of future fuel deployment under a 23% 2030 CI target as a completed custom profile in the Illustrative Compliance Scenario Calculator, attached to this submission. Our proposed target trajectory is given below:

Year											
2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
6.40%	7.80%	9.20%	10.60%	12.00%	13.40%	15.00%	16.60%	18.20%	19.80%	21.40%	23.00%

124-5 cont.

This trajectory, when applied to the *HIgh Performance* credit generation trajectory using our High-VMT assumption yields the following credit bank projection:



This reflects modest continued growth until after 2020, at which point the substantial bank of credits that accumulated during the period of frozen CI targets in 2015-2016 is gradually spent down until the mid-2020's, when ZEV deployment reaches high enough levels that the non-linear effect they generate begins to dominate the system, resulting in robust credit bank growth and a program well positioned to continue its ambition after 2030. The credit bank drops to 6 million tonnes in 2026, or almost 50% of expected obligations, which represents a strong reserve against unexpected challenges. The robust bank of credits will insulate this

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trajectory against under-performance by some technologies or fuel demand above even Cerulogy's High-VMT scenario.

Critically, the 23% target ensures a robust and predictable demand for LCFS credits in the latter years of the re-adopted program, which will give investors confidence to make major commitments of capital now, with the expectation that their investment will benefit from LCFS credits throughout the next decade.

A 24% Target is Also Feasible Under the Same Assumptions

The Cerulogy research indicates that credit generation under likely technological pathways tends to accelerate in the latter half of the next decade. Absent a commensurate increase in targets, this could result in the development of a substantial bank of credits which sends challenging market signals to prospective low-carbon fuel project developers considering major capital investment projects which would require a long payback. The 23% scenario proposed above includes increases in CI targets of 1.4% per year through 2024 and 1.6% per year thereafter. By shifting the CI target schedule to a slower 1.3% per year growth rate during the early years of the program, a 24% 2030 target can be reached without preserving a bank of at least 10 million credits throughout the duration of the program. Like the 23% trajectory above, the fuel demand modeled in this analysis is the more conservative High-VMT case. 124-5 cont.

Year

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
6.30%	7.60%	8.90%	10.20%	11.50%	13.00%	14.50%	16.00%	18.00%	20.00%	22.00%	24.00%

This trajectory yields greater emissions benefits in 2030 and beyond and more closely matches expected credit generation patterns, though the 23% trajectory in the previous section delivers greater near-term emissions benefits and a presents a more stable yearly rate of target increase. **NextGen suggests that in addition to the 23% target trajectory presented in the previous section, Staff also consider a back-loaded 24% trajectory as shown here.**

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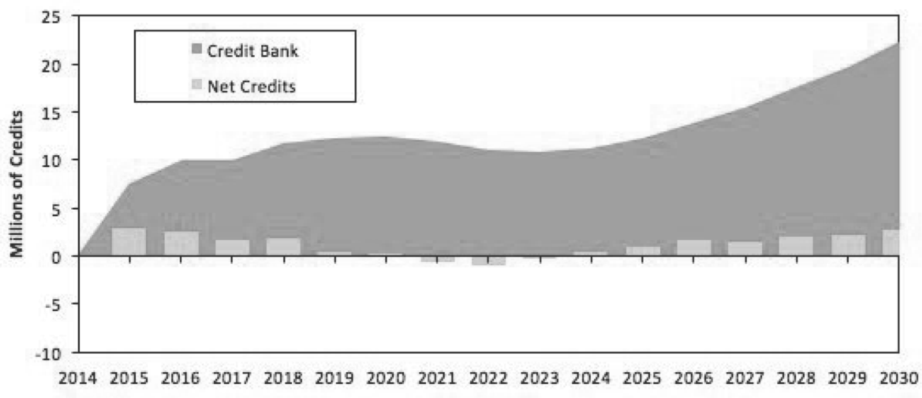

124-5 Cont.

Designing the Re-Adopted LCFS to Handle Uncertainty

We recognize that CARB and staff seek to preserve flexibility for the program to adapt to a dynamic market, which will almost certainly develop in ways we do not foresee at present. Staff have indicated a concern that adopting a more ambitious target increases the risk that targets would have to subsequently be adjusted downward in the event that the development of low-carbon fuels lagged projections or fuel consumption exceeded expectations. We agree that stable targets create predictable market signals and support a healthy market for investments into low-carbon fuel production and distribution infrastructure. We disagree, however, that adopting targets below the feasible maximum and planning to adjust upwards once it is clear that the market can support higher targets is a preferable option. 124-12

The Cerulogy research clearly demonstrates that there is a significant likelihood that credit generation will rapidly increase after the mid-2020's, as ZEVs become a significant fraction of the vehicle fleet. ZEVs not only generate credits through charging or fueling, they reduce deficits by displacing gasoline and generally reduce the total primary energy consumed by the transportation system, since they are several times more efficient than internal combustion engines. These effects mean that almost every scenario examined by Cerulogy indicated a rapidly growing credit bank by 2027 and in many cases, a 2030 credit balance well in excess of half the total 2030 credit obligation. Even the sensitivity cases which evaluated under-performance of the program and ran substantial deficits during the mid-2020's had regained balance by the end of the program and were on a trajectory to develop a significant credit surplus. 124-14

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The fact that strong credit surpluses emerge by the late 2020's under such a wide variety of conditions will not be lost on LCFS market participants. Without a stronger target in the out years of the program, participants will perceive a very loose market in the latter years of the next decade, which will create a strong disincentive to make investments which require more than a few years to pay off, such as commercial-scale biofuel production capacity, electrical system upgrades to support high-speed charging and novel supply chains to support innovative fuels and vehicles. Potential financiers or underwriters of projects, who typically assign very little value to future policy instruments like LCFS credits at present, will see even more risk that credit prices will be unacceptably low post-2025. Conversely, a higher target, especially in the out years, creates more certainty that revenue from the LCFS credits generated by a project will remain strong throughout the full decade. Waiting for a future mid-term review or program amendment to raise targets does not create the same certainty; project developers will be unlikely to invest substantial capital in long-payback projects which depend on a favorable outcome from a regulatory action to ensure profitability. By the time that CARB had enough data to conclusively prove that credit generation was going to exceed that required to support a 20% target and completed the necessary process to develop a higher target, it would be unlikely to be adopted before the middle of the next decade. At that point, the 2030 sunset of the program would be a disincentive to major, long-payback investments. Therefore, *now may be the only window of opportunity to encourage the development of projects with a payback period longer than five years*. To encourage these longer-payback projects, CARB needs to create the expectation that LCFS credit prices will remain stable throughout the re-adopted period; a target that is reasonably expected to under-shoot likely credit generation will not produce this result.

124-14 cont.

We recognize Staff's valid concerns about the risk of having to reduce targets. These concerns can, however, be addressed through effective and transparent program design, without the need to select an overly conservative target. Specifically, we strongly suggest staff develop a list of key metrics, and targets for these metrics, that will inform CARB's thinking about the relative balance of credits and deficits through the first half of the re-adopted program. Staff should, to the greatest extent feasible, try to create a clear expectation of whether targets are likely to increase or decrease based on the performance of these metrics. Some suggested metrics are:

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- ZEV fleet size
- Average ZEV driving activity (vehicle miles traveled or VMT) per vehicle
- RNG development, including average CI
- Natural gas vehicle fleet size, which determines capacity to use RNG 124-14 Cont.
- Deployment of CCS, including under-construction or contractually committed
- Fossil fuel demand
- Advanced biofuel capacity
- Status of Federal and State fuel economy or tailpipe GHG emissions standards
- Status of LCA or iLUC research, which would affect CI scores under LCFS

To be clear, we are neither suggesting nor supporting a proposal to determine mid-term adjustments purely by algorithm. There will always be a need for Staff and Board members, in consultation with the public and key stakeholders, to exercise their judgment regarding targets. CARB can minimize the risk that future adjustments send a problematic signal to market participants by creating a transparent set of metrics that can give the public a sense of whether target adjustments are likely.

Higher LCFS CI Targets Support California's Broader Climate Policy

The LCFS should be considered not just as an independent policy, but as one element of California's portfolio of climate change policies. The LCFS constructively interacts with almost every other element of climate policy, by reducing the number of Cap-and-Trade permits consumed by the transportation sector, supporting the deployment of clean vehicles, providing a market for RNG that would otherwise have been lost as fugitive methane from dairies or organic waste disposal, and providing flexible demand on the grid to support renewable electricity. In almost every case, the synergistic interaction between LCFS and other climate policies is improved under a higher target. 124-18

The LCFS' effect on the cap and trade market is particularly important to consider. As the LCFS replaces high-emitting petroleum with low-emitting alternatives, fuel providers will be obligated to buy fewer allowances to cover emissions from their fuels. This will tend to put downward pressure on cap-and-trade allowance prices and minimize the risk that additional allowances will be released from the cost containment reserves. In the absence of strong complementary policies to reduce emissions from the transportation sector there will be significant upward pressure on allowance prices. during the 2020-2030 time period. The LCFS will moderate this upward pressure, resulting in lower cost of compliance for all entities with a compliance obligation. ICF International's 2016 report supports this intuitive understanding of the dynamics between LCFS and Cap-and-Trade, they estimated that a 20% LCFS would reduce cap-and-trade allowance prices by $29 compared to a 10% target.[7] Neither NextGen nor ICF claim that the savings from lower allowance prices would fully offset the costs associated with a higher LCFS target, however it is clear that these savings would significantly mitigate such costs. 124-18 Continued from previous page, continues to footnote below

It is also important to note that the LCFS typically causes lower fuel price impacts to consumers than a Cap-and-Trade program of equivalent stringency. Under the Cap-and-Trade program the full marginal cost of emission allowances can be expected to be passed through to consumers, whereas only a fraction of the marginal cost of LCFS credits are expected to be passed through, proportional to the CI reduction target. For example, most retail transportation fuels are blends of petroleum and lower-carbon biofuel, such as E10 (10% ethanol, commonly sold as retail gasoline) and B5 (5% biodiesel, commonly sold as retail diesel). In blended fuels, the high-carbon fraction of each gallon functionally subsidizes the low-carbon fraction through LCFS credit transactions. Producers see the price-based incentive to reduce emissions, but only a fraction of that price reaches the consumers, which minimizes the impact on prices at the pump. LCFS therefore offers the chance to reduce transportation emissions with less price-base impact on consumers and less risk of regressive effects than relying more heavily on Cap-and-Trade. 124-20

Numerous stakeholders, including NextGen[8], have expressed concern that the recently adopted Scoping Plan assumes, without sufficient justification, massive reductions in emissions driven by the Cap-and-Trade Program. Complementary measures yield a much smaller fraction of total emissions than in previous years. Increasing the LCFS CI reduction target would reduce the burden on the Cap-and-Trade system by driving emissions down through complementary measures. Each percentage point of additional CI target yields 3-5 million tonnes of additional cumulative carbon pollution reduction through 2030 when phased in over the last 5 years of the program. The proposal we offer above would be expected to reduce emissions by a cumulative 16 million metric tons, compared to CARB's suggested 20% target.[9] 124-21 continues to footnote below

[7] http://www.caletc.com/wp-content/uploads/2016/08/Final-Report-Cap-and-Trade-LCFS.pdf 124-18 cont.
[8] See: https://www.arb.ca.gov/lispub/comm2/bccomdisp.php?listname=ct-3-2-18-wkshp-ws&comment_num=28&virt_num=22
[9] This value determined by summing total credit generation from CARB's 20%, High-ZEV, High-Demand scenario, and NextGen's Suggested Compliance Scenario. The difference between the two is 16 million metric tons. 124-21 continued from above

NextGen Comments on Other Proposed Provisions

NextGen would again like to commend CARB and the LCFS Program Staff on their extensive series of workshops, strong analysis and openness to constructive discussion throughout the LCFS rulemaking process. What follows is NextGen's comments on a wide variety of program design issues, for which Staff have requested input from stakeholders. 124-22

NextGen Supports Adding a Carbon Capture and Sequestration Protocol

Staff have proposed to add a credit generation pathway to reflect carbon capture and sequestration (CCS) to the LCFS. CCS can include a variety of methods of durably storing carbon in a manner which prevents it from returning to the atmosphere. Within the scope of transportation fuel production, the most applicable form of CCS is likely to be capture of carbon dioxide gas, compression and injection into geologic storage sites such as underground caverns, depleted petroleum reservoirs and saline aquifers. CCS is a relatively new technology; there are a limited number of demonstration projects at present, but there is a broad consensus in the extant literature that CCS is technologically feasible, scalable and could become cost effective, especially in jurisdictions which adopt a carbon price. While it may be possible for California to attain its clean energy goals without using CCS, most projections of energy system deployment compatible with limiting climate change to well below 2 degrees Celsius of maximum warming require a significant deployment of CCS.[10] California can continue to demonstrate its global climate leadership by helping deploy CCS at commercial scale to demonstrate the technology and begin driving costs down to commercially-viable levels. 124-23 124-24 continues to footnote below

NextGen California **supports the inclusion of CCS pathways in the re-adopted LCFS**. Given the novelty, uncertainty and risk associated with this technology, we urge CARB to find an appropriate balance between supporting maximum deployment of this technology while protecting California, and the climate, from associated risks. We urge CARB to adopt a rigorous and transparent process for certifying CCS pathways and verifying that their real-world performance matches the on-paper claims. We recognize that CCS policies work on a time horizon which is quite different than most projects relevant to the production of transportation fuels; injection of CO_2 may occur over decades and post-injection monitoring should extend for at least a century, in order to match the common definition of "sequestered" carbon. Over these time scales, the technology used to sequester carbon and monitor completed projects will change significantly; a body of literature reflecting 124-25

[10] e.g. https://www.ipcc.ch/report/ar5/ 124-24 continued from above

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real-world experience will also emerge. CARB must design its CCS protocols with the understanding that we are only beginning to develop technical fluency in CCS. As such, current policies surrounding CCS should err on the side of risk-aversion, but acknowledge that change in regulatory, technical and monitoring practices are certain to occur. As we gain more experience with CCS operations, CARB can relax provisions which may turn out to be unnecessary. If a conservative near-term policy structure proves to be an impediment to deployment of the first generation of commercial projects, it would be better for CARB to support a set of pilot projects through a process unconnected to the LCFS program than to establish pathways under the LCFS that incentivize deployment of unnecessarily risky projects. 124-25 cont.

Risk Mitigation from CCS Projects

A suitably risk-averse CCS protocol should balance the need to provide as much financial incentive to project developers who can accept the risk involved in deploying novel technology against the need to protect the public from potential risks due to improper storage or catastrophic release, as well as ensure that LCFS credits are granted in proportion to actual environmental benefits of the program. We support a requirement for 100 years of monitoring after injection ceases, though we accept the premise that as our understanding of CCS improves, this may turn out to be unnecessary. We suggest that rather than requiring a comprehensive 100-year monitoring plan to be agreed upon prior to project commencement, a project review be conducted when injection ceases to determine appropriate monitoring protocols using the best available methods at the time. Project developers should be obligated to demonstrate that carbon is being durably sequestered for a century after injection terminates, but the specific method used to make that determination can be made later, with the benefit of additional understanding. 124-27

Similarly, CARB should require that project developers remain liable for the risk that CO_2 may be released from the project at some date after injection. In the event that a sequestration project loses containment of part or all of the sequestered CO_2, project developers should be liable for costs associated with remediating immediate environmental harms, preventing further loss of contained CO_2 and the damage to the climate from the release of carbon pollution. These risks may be addressed through provision of a suitable risk bond by the developer, or by claw-back provisions relating to LCFS credits in the event of release - though we would note that over the time scales relevant to CCS projects, claw-back provisions may be difficult to enforce in practice. Alternatively CARB may wish to consider holding part or all of the LCFS credits, or other carbon instruments, in escrow and transferring them to the project developer over the duration of the project on a schedule that 124-28

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reflects the time-adjusted value of the sequestered carbon. Since CO_2 has a long atmospheric lifespan, delaying emissions reduces the impact of climate change over most time scales relevant to policy making, even if aggregate emissions remain the same. This is to say, it is better for the climate to release a ton of carbon in the future than it is today.[11] CARB may wish to base protocols relating to the release of sequestered CO_2 on the basis of rewarding project developers for the time carbon is sequestered, in the event of catastrophic release. Holding some LCFS credit value in escrow and distributing to project developers over time to reflect the value of the time sequestered carbon has spent underground reflects the risk of reversion, creates an incentive to maintain the project through its post-injection phase and ensures that developers will have a stream of revenue available for ongoing maintenance and monitoring.

124-28 Continued from previous page, continues to footnote below

Potential Scope of CCS

The combination of LCFS credits and Federal Section 45 (Q) tax credits could ultimately yield net revenue of over $150 per tonne for sequestered carbon, well over the value that multiple authors have concluded is necessary to support industrial-scale CCS in a variety of near-term applications.[12] We feel that the incentive provided by the LCFS and 45 (Q) credits is likely to be sufficient to support the deployment of a sufficient number of early projects, which will provide critical support for the CCS industry while providing valuable experience to CARB regarding real-world performance and regulatory considerations. NextGen and the Union of Concerned Scientists evaluated the potential for near-term deployment of CCS projects under the LCFS and found there was significant potential in at least two categories: capture of ethanol fermentation tank emissions and as modification to steam methane reformers (SMR) at existing petroleum refineries.[13] These two pathways take advantage of high-concentration or high partial-pressure streams of CO_2 that occur in existing industrial processes. These streams offer a favorable environment for capturing CO_2 at relatively low cost, which makes them likely options for early commercial deployment.[14] This analysis concluded that there was potential for several hundred thousand to several million tonnes of CO_2 sequestration per year through 2030 from these sources.

124-29 continues to footnote below

124-30 continues to footnotes below

[11] Kendall, A. (2012). Time-adjusted global warming potentials for LCA and carbon footprints. *International Journal of Life Cycle Assessment*, *17*(8), 1042–1049. http://doi.org/10.1007/s11367-012-0436-5

124-28 continued from above

[12] http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapCarbonCaptureandStorage.pdf

124-29 cont.

[13] Add URL for re-submitted CCS memo here.

[14] See: D.L. Sanchez, N. Johnson, S. McCoy, P.A. Turner, K.J. Mach. "Near-term deployment of carbon capture and storage from biorefineries in the United States" Proceedings of the National Academies of Sciences (In Press). for more information on CCS at ethanol facilities and "Current Central Hydrogen Production from Natural Gas with Sequestration" at https://www.hydrogen.energy.gov/h2a_prod_studies.html for more information on CCS at steam methane reformers.

124-30 continued from above

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There is potential for significantly more deployment of CCS than just these applications, however. Post-combustion capture, in which CO_2 is scrubbed from normal combustion exhaust, may also be possible at costs below the expected combination of LCFS credits and 45 (Q) tax credits. This method of capture is potentially applicable to almost any large-scale stationary combustion process including power plants, refineries and biofuel production facilities. If post-combustion capture is widely deployed at all possible points in the transportation system, there could be the potential for tens of millions of tonnes of total LCFS credit generation per year. This would necessitate a fundamental re-examination of California's climate and energy policies. If post-combustion capture deploys widely, CI targets in excess of 30% may be required to ensure that the LCFS market stays strong enough to support alternatives to petroleum. While we feel commercial deployment of post-combustion CCS before 2030 is unlikely to occur at scales sufficient to necessitate such a re-examination, we urge CARB to monitor this technology closely and be prepared to take action. 124-31

NextGen Opposes Proposed Capacity Based Infrastructure Credits

Several stakeholders have requested that CARB institute a new protocol for awarding LCFS credits for the capacity of installed fueling infrastructure, rather than solely for the quantity of fuel dispensed, as is the practice under the current program. This concept is most often discussed in regards to hydrogen fueling stations, however stakeholders have also proposed extending it to electric or natural gas vehicle fueling equipment as well. 124-32

NextGen California opposes the creation of capacity-based LCFS credit generation pathways. We see this as an abrupt departure from the established, and quite successful, structure of the existing program. Fueling infrastructure providers already have ample incentive to install commercial and/or public fueling facilities: they are eligible to claim the LCFS credits from fueling activity at their stations. Adding a new pathway breaks the fundamental relationship upon which the LCFS is based: that credits are awarded for activities which actually reduce emissions. Creating this new credit pathway would establish a troubling precedent that the program will assign credits, which have real financial value, based on uncertain expectations of future emission reductions. Doing so would essentially move the risk that a project will fail to live up to its projections onto California residents; if a given piece of fueling infrastructure which was supported by capacity-based credits did not produce the expected emissions cuts then California the LCFS would not yield the actual reductions implied by the program's credit transactions and the state would be off track to hit its SB 32 goals, other programs Would have to make up the shortfall. The resulting costs would be passed on to consumers.

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Capacity-based credits also risk conflicting with, or unnecessarily complicating, energy infrastructure planning at other agencies. The California Energy Commission and California Public Utilities Commission both support infrastructure deployment through a variety of programs. CARB would have to consult with either or both agencies before awarding capacity-based LCFS credits, or risk interfering with, or duplicating, efforts by those other agencies. Infrastructure planning at the project level is a more appropriate for other programs outside the LCFS. 124-32a Cont.

We recognize that many fueling infrastructure developers are finding it difficult to develop project capital from expected LCFS credit revenue, this problem is common throughout the alternative fuels space. We support efforts to make LCFS credits a more secure financial instrument which could back debt or equity for project capital. We support efforts to reduce policy risk, which is a main reason why financial institutions often under-value future LCFS credit revenue, and we would support efforts to address this problem in a more appropriate way, such as a State-backed green bank, loan guarantees or policy risk insurance.

NextGen Supports Using LCFS Credit Value to Provide Point-of-Sale ZEV Rebates

As the Cerulogy research demonstrated, ZEVs, especially battery electric and plug-in hybrid vehicles, are a key part of California's long-term sustainable transportation future. The primary limiting factor on their total contribution towards attaining the state's climate and clean air goals is rapid deployment. Sales will need to rapidly expand in order to meet the 5 million ZEV target from Executive Order B-48-18. Rebates are a key tool to drive early sales and have significantly contributed to ZEVs rapid growth from essentially zero a decade ago to over one percent of new car sales. 124-33

At present, the LCFS supports several rebate programs offered through utilities. LCFS credits from un-metered household charging are transferred to utilities, who are required to use the revenue to support the continued expansion of the electric vehicle market. Many offer rebates to EV owners, though these rebates may not be received by the purchaser until weeks or months after the vehicle is purchased. Owners cannot currently determine their eligibility for rebates at the time and place of sale; they must either apply after they purchase the car and risk being denied a rebate, or they must pre-qualify for a rebate under a program recently developed by the CVRP administrator. Pre-qualification must occur several days in advance of purchase, which presents a significant procedural hurdle for potential buyers and does not align well with the dynamic, incentive-based

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sales approach of most auto dealers. Lower-income purchasers are particularly affected, as they may lack the funds to pay a higher price for a vehicle and wait for a rebate.

The solution is a point-of-sale rebate, which can be deducted from the purchase price, with the rebate being seamlessly conveyed to the dealer. **NextGen strongly supports efforts to develop a point-of-sale rebate funded by revenue from un-metered residential charging LCFS credits.** Point-of-sale rebates are widely understood to be more effective at driving consumer behavior and a rebate of this type would more effectively support existing State efforts to accelerate the penetration of ZEVs into the market. A point-of-sale rebate would almost certainly deliver more value to the state than the current slate of utility-sponsored rebate programs. 124-33 Cont.

Some EV manufacturers, notably Tesla, have proposed a model in which unmetered household charging credits are assigned to vehicle manufacturers at the time of sale and the value of those credits are converted into a rebate by the manufacturer. Such a program must be carefully designed to ensure that the interests of Californians, including current EV owners, prospective EV owners and utility customers are protected. In particular: 124-34

LCFS Credit Revenue Must be Predominantly Used to Support EV Deployment

Concepts for a LCFS-funded rebate program that have been put forward by EV manufacturers often indicate that they will recover administrative and financial costs from the LCFS revenue, including the cost of capital needed to convert ongoing streams of LCFS credit revenue into up-front rebates and a risk premium to reflect policy or market risks. We recognize the need for manufacturers to cover administrative costs and agree that a reasonable risk premium is warranted given the uncertainty surrounding any climate policy instrument. Manufacturers should not, however, routinely make substantial profit on the administration of a program meant to dispose of policy instruments which support a public good, clean air. Manufacturers will have ample opportunity to derive profit from increased sales of their product. If the cost and risk involved in managing a rebate program is too great for them to bear, there are several non-profit organizations with deep expertise in managing rebate programs which could do so. 124-35

To this end, any organization which seeks to receive LCFS credits for the purpose of providing a point-of-sale rebate must provide a transparent proposal for administering the program for CARB and allow for public

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review. This must include:

- A clear indication of both expected revenue and expenditure
- A verifiable plan of action to cover the possibility that LCFS credit prices will be above plan assumptions, resulting in more revenue than anticipated.
- Clear identification of any administrative costs, financing costs, risk premiums or other revenue which will not directly go towards ZEV deployment
- Demonstrated technical capacity to assess the number of LCFS credits generated by the charging of the vehicles for which LCFS credits will be assigned to the manufacturer. 124-35 Cont.
- Demonstrated technical capacity to exclude charging at public, commercial, or independently-metered charging stations from the assessment of total LCFS credit assignment. Credits from these stations shall remain with the station operator, as under the current LCFS protocol.
- Regularly scheduled reviews to demonstrate that the program is actually performing in line with expectations.
- A commitment to allow an independent audit at CARB's discretion

We also strongly recommend that if CARB chooses to develop a LCFS-funded point-of-sale rebate protocol along the lines proposed by EV manufacturers, they do so with the consent of utilities who currently administer programs to use unmetered residential charging credits. We appreciate auto manufacturer's interest in developing an effective rebate program, and believe it will be most successful if implemented with the cooperation of utilities and with robust oversight.

A Possible Alternative to a Manufacturer-Administered Program

We intend to continue working with stakeholders to develop a mutually agreeable solution by which LCFS credits could be used to fund a point-of-sale ZEV rebate. Designing a manufacturer-based program is complex and requires coordination by a broad variety of stakeholders. It may not be practicable to do so under the 124-36 timeline of the current rulemaking. In that event, we **suggest that CARB allow owners to assign unmetered residential charging LCFS credits to the organization or recipient of their choice at the time of sale.** We suggest that CARB retain a role in approving programs that are eligible for assignment, using criteria similar to existing provisions regarding utility use of LCFS credit revenue.

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This would allow manufacturers, auto dealers, financial institutions and other stakeholders to offer a range of rebate options at the time of sale. In practice, these could be provided as a point-of-sale rebate by contractual agreement between the entity offering the rebate and the dealer. We anticipate that under this model, manufacturers would be well-positioned to offer rebates like those proposed by Tesla and other manufacturers.

124-36 Cont.

Allowing assignment of unmetered charging credits allows institutions to experiment with various models of financing and rebates without having to seek regulatory approval for each modification to the program. It is entirely possible that this change alone could facilitate a broad transition to a system much like that proposed by manufacturers, without the State having to unilaterally decide upon that as the solution.

NextGen Supports the Adoption of Time-of-Use Charging ("Smart Charging") Credits

LCFS program staff have proposed adding a Time-of-Use EV charging, or "Smart Charging," bonus credit. This would be applied in addition to the normal baseline credits for charging an EV. Charging activity that occurred between 9:00am and 4:00pm would be eligible for a credit of an amount which reflects the expected emissions savings from using curtailed solar energy rather than the normal marginal grid mix. The estimated emissions savings would vary on a quarterly basis and be regularly updated to reflect current grid conditions. 124-37

NextGen California strongly supports the inclusion of Smart Charging credits, per Staff's proposal. Significant amounts of solar energy are regularly curtailed between 9:00am and 4:00pm, encouraging vehicle charging during that time can make use of this otherwise wasted resource. This credit particularly supports broad deployment of workplace charging infrastructure, which is a critical need in California.

We suggest Staff consider whether the Smart Charging credit could be expanded to provide a dis-incentive for charging during times of peak grid demand, such as 5:00pm to 9:00pm, however we recognize that dis-incentive provisions are more complicated than incentives, and so may take more time and effort to design. We also encourage CARB to move as quickly as is feasible towards routinely using real-time telematic or charger data to base incentives around actual grid conditions, rather than seasonal estimates.

NextGen Supports Renewable Charging Credits, Provided They Yield Additional Emissions Reductions 124-38

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Staff have proposed adding a new LCFS credit pathway, similar to the Smart Charging pathway discussed above. This would function as an additional credit available to EVs which charge using zero-carbon renewable electricity (RE). This proposal would support the continued deployment of renewable energy while also reducing transportation-related emissions. RE credits would be available for charging activity supplied under a Green Tariff rate plan, which procures renewable energy sufficient to meet the customer's aggregate energy needs. 124-38 Cont.

We, along with other stakeholders, have expressed concern that the RE provisions in the proposed rule could lead to significant issuance of RE charging credits without a commensurate reduction in emissions from either the electrical grid or the transportation system, compared to issuing credits at the grid average rate. California has significantly over-complied with current Renewables Portfolio Standard (RPS) requirements, which means that there is an excess of renewable energy available to in-state utilities and balancing authorities, compared to their regulatory obligations. This excess means if a utility customer switches from a standard grid-average plan to a Green Tariff plan, they will nominally be getting lower-emitting power but in reality, they could merely exchange their grid mix supply for some of the excess renewable supply, resulting in net emissions from the grid that have not changed as a result of their switch. Charging station operators could sign up for a Green Tariff plan, receive additional LCFS credits for their activity without actually reducing emissions more than if they had received credits according to the standard grid average rate. This breaks the fundamental relationship upon which the LCFS is based: market-based incentives are granted for activity which actually reduces emissions compared to the status quo. 124-39

Since the initial concepts were presented in 2017, Staff have clarified that Green Tariff plans must also demonstrate that they must procure renewable energy which is in addition to any required under other policy mandates. Specifically, § 95488.8 (i)(1)(B)(2) of the proposed regulation order states:

> "All electricity procured by any LSE for the purpose of claiming a lower CI must be in addition to that required for compliance with the California Renewables Portfolio Standard or, for hydrogen produced outside of California, in addition to local renewable portfolio requirements" 124-40

We urge CARB to clarify this provision to ensure that it results in a strict application of an additionality test for any renewable electricity which seeks eligibility for RE credits. Specifically:

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- This provision should specify "... in addition to that required for compliance with the California Renewables Portfolio Standard, _or other renewable energy requirements..._" This will reflect the fact that other Federal, State or Local policies may require the deployment of RE and any such deployment would be subject to the same additionality concerns as relate to the RPS. Electricity used to satisfy voluntary programs or which has been credited under other market-based mechanisms should still be eligible for compliance. 124-40 Cont.
- "In addition to compliance with the California Renewables Portfolio Standard" should be clarified to indicate that renewable energy in excess of that standard's requirements in a given year is not necessarily eligible for RE charging credits. To satisfy additionality, renewable electricity must have been generated by a resource which has never been used for compliance with the RPS or another renewable energy mandate. If electricity from a generator or Renewable Energy Certificates from a generator are, at some point, used to demonstrate compliance with a renewable energy mandate, this is strong evidence that the generator would have been operating whether or not LCFS credits were part of its revenue structure; it should rightly be considered part of the existing grid mix and EV charging it supports would not result in additional emissions reductions.

This functionally means that RE generators must choose whether they wish to sell in to the LCFS credit market or the broader pool of grid resources. While this limits the potential market for RE generators to some extent, we are confident that the extra revenue associated with LCFS credits, and the potential for dedicated contractual agreements, such as Power Purchase Agreements (PPAs) with charging service providers or other aggregators of charging activity using book-and-claim accounting will create a robust market for RE generation which can be dedicated to LCFS charging. 124-41

We note that the need to exclude generators which were previously used for compliance with RPS or other renewable electricity requirements is a direct result of California's significant over-compliance with its RPS (which is, in most respects, a positive development). In areas where no excess of renewable electricity above mandated requirements exists, charging on a Green Tariff or similar rate plan implies additional renewable energy must be procured. In jurisdictions where there is no excess generation of renewable energy, which may include California as RPS requirements increase, the requirement in this point could be relaxed. 124-42

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- The provision should clarify that RE credits should be issued only when there is clear evidence that the charging behavior which generated those credits resulted in real reductions in emissions, beyond what would have occurred in absence of the RE credits.

124-43

We applaud CARB and LCFS Program Staff for recognizing the need to ensure RE credits yield additional reductions compared to a business-as-usual case. **NextGen supports the inclusion of Renewable Energy charging credits, provided that they satisfy a strong test of additionality.** The clarifications described above would help develop a suitably strong test of additionality.

NextGen Supports Proposed Alternative Jet Fuel Provisions

At present, air travel accounts for approximately 10% of transportation-related GHG emissions in the U.S. Decarbonizing this sector presents a particular challenge for policymakers since many of the technologies which show promise towards reducing on-road emissions will struggle to meet the technical requirements for commercial air travel. Low-carbon analogues to petroleum-based jet fuel, such as biofuels, are widely regarded as an obligatory element of a sustainable transportation system. The LCFS is therefore an excellent framework from which to develop market-based incentives.

124-44

NextGen strongly supports the inclusion of low-carbon alternatives to conventional petroleum jet fuel under the LCFS. We agree with the basic principles outlined by Staff, but suggest one additional consideration:

124-45

We recommend that CARB thoroughly evaluate the equity and environmental justice impacts of including alternative jet fuel in the LCFS. We are concerned that since alternative jet fuels are fairly analogous to renewable diesel - they are both produced by the catalytic hydrogenation of non-fossil oils such as vegetable oil, used cooking oil or tallow - and so could lead to competition for feedstock and production capacity. This competition could affect progress towards reducing diesel pollution in California, which is a critical step towards addressing many of the critical air quality issues affecting disadvantaged communities. Similarly, the incorporation of alternative jet fuels under the LCFS will ultimately result in a net transfer of revenue from on-road fuels, as gasoline and diesel providers purchase credits for compliance, to aviation fuels, which will be one source of such credits. Given that the typical airline passenger is of higher-income than the typical driver, this wealth transfer could lead to dis-equitable outcomes. We wish to be clear: we are not aware of any research

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into the equity impacts of these particular fuels in a context relevant to California and have seen no evidence that indicates that including alternative jet fuels under the LCFS will lead to dis-equitable outcomes. We anticipate that the equity-promoting impacts of cleaner air around airports and reducing the impacts of climate change are of greater magnitude than the concerns discussed above. Given California's strong progress in the promotion of justice and equity, it is worth taking a deliberate and objective look at these provisions before they become deeply entrenched within the program. 124-45 Cont.

NextGen Supports Linking California's LCFS with Equivalent Programs in Other Jurisdictions

California's LCFS has become a model for global clean fuels policy. British Columbia and Oregon have already adopted similar programs, Washington State has attempted to do so and the Canadian Federal Government is currently developing a Clean Fuels Program largely based on similar concepts. Several stakeholders have explored the possibility of linking LCFS credit markets, in order to improve liquidity, reduce the risk that fuel producers will relocate fuel-consuming activity into jurisdictions with no fuel carbon policy ("leakage"), and maximize the total market signal to innovative clean fuel producers.

NextGen supports linking California's LCFS with equivalent programs in other jurisdictions, provided that this does not result in a net reduction of aggregate program stringency and that California retains authority to set its own reduction targets. 124-46

Linking LCFS credit markets, in a manner analogous to the cap-and-trade program linkages under the Western Climate Initiative can help improve the power and efficiency of the LCFS, while reducing administrative burdens. This is particularly useful for smaller jurisdictions which may lack the capacity to develop and administer a LCFS of their own. Linked markets also reduce the incentive for leakage by encouraging action in other states or regions and reducing the number of uncontrolled jurisdictions to leak to.

We urge Staff to explore opportunities for linkage with other LCFS programs, provided they use equally robust and stringent methods for assessing the carbon intensity of fuels as CARB. We recognize that since California's LCFS targets are significantly ahead of other jurisdictions, since its LCFS has been in effect for far longer, it will be difficult for potential new partners to adopt a LCFS at an equivalent nominal target. Where fuels are credited in jurisdictions other than the one to which they're physically delivered, their credit generation should be assessed relative to the targets in the crediting jurisdiction, rather then the one of delivery.

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By allowing some limited flow of credits across borders, linked markets can reduce emissions from the transportation of fuels to market. We urge Staff to seek an appropriate balance between maximizing overall system efficiency and ensuring that communities in high-demand jurisdictions receive air quality and economic benefits from the fuels used to satisfy their obligation under a linked program. 124-46 Cont.

NextGen Supports the Including Credit Generation Pathways for Co-Processing of Biomass Feedstock and Emissions-Reducing Investments at Refineries, Provided they are Adequately and Transparently Justified

Staff have proposed including credit generating pathways relating to co-processing of biomass feedstock in petroleum refineries as well as from investments in emission-reducing technology. There is ample evidence in scientific literature that both of these pathways can reduce emissions from transportation fuel production systems. Accordingly, **NextGen supports the inclusion of these pathways, provided that sufficient data is made available to CARB and the public to ensure they provide real, verifiable and additional emissions reductions from the full fuel production system they affect.** Specifically, Staff has asked for input on the scope of data which should be provided by developers of these types of projects in order to certify a pathway. Refinery operators, who would be the most common applicants, have argued that data on emissions should be limited to the specific refinery process affected by the proposed investments which would result in credit generation. 124-47

Process-specific data is sufficient in cases where the proposed project has no effect on any other process in the refinery. Simple efficiency improvements, such as insulation, displacement of fossil energy by renewable energy for heat or pumping burdens or reductions in waste may be amenable to process-specific analysis. Refineries are complex technological systems in which materials and energy are routinely exchanged between various production units, with coproducts often utilized to maximize production of revenue-generating material and heat exchangers used to recover waste heat. Accordingly, relatively small changes to a single process may have far-reaching indirect effects within the refinery. For example, reducing waste heat from a process may require more energy inputs elsewhere if energy from the waste heat stream was recovered for use in other processes. Improving conversion efficiency in a process may reduce the flow of useful co-products to other processes, necessitating their make-up with additional material. In these cases a consequential, facility-level analysis is the only way to accurately assess actual impacts.

Where project developers claim that a process-specific analysis is sufficient to quantify the emissions reduction attributable to a given project, CARB should require project applicants to provide sufficient data to conclusively demonstrate that there are no significant effects on other processes within the refinery. The burden of proof should rest on the project developer to demonstrate the sufficiency of process-specific analysis and CARB should err on the side of a more expansive analytical scope where there is uncertainty regarding the scope of impacts. We recognize that some of the data needed to substantiate project developers' claims may be confidential business information, in this case CARB can take appropriate precautions to protect such data, however it must ultimately be made available to CARB and, if applicable, third-party verification bodies. 124-47 Cont.

For investments in refinery efficiency, CARB should require that such investments improve efficiency beyond industry standards before they are eligible to generate reduction credits. LCFS credits should only be awarded where investments represent a clear effort to do more than regulation, industry standards or normal retrofit schedules would otherwise require. CARB should seek to develop a set of standards which clearly define industry best practices and use that as a guide to help determine which projects qualify for LCFS credits. CARB should look to resources like global regulatory standards, industry best practice documents and refinery benchmarking efforts.[15] 124-48

NextGen Supports the Inclusion of Charging Credits for New Modes of Transportation

At pre-rulemaking workshops some stakeholders inquired as to whether charging activity that supported new modes of electrified travel, such as e-bicycles or electric aircraft, including drones, would be eligible for LCFS credits. Staff requested input from the community on this subject. At these workshops, some stakeholders expressed concern that these modes would result in a net increase in energy used by the transportation sector since they may increase the amount of flying, in the case of electric aircraft, or displace active or public transportation in the case of e-bikes. We feel that it is unlikely that such vehicles will account for a significant amount of energy consumption relative to the transportation sector as a whole, so including these new modes under the LCFS can help provide support for innovative modes of travel. 124-49

We suggest, however, that CARB limit the maximum credit generation for fuels delivered to these new modes to a relatively small fraction of the total credit generation until there is sufficient data to assess whether they, or any novel mode of transportation, would result in a significant net increase in transportation energy

[15] e.g. the Solomon and Associates refinery benchmark https://www.solomononline.com/benchmarking

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consumption. The LCFS is built on the fundamental assumption that alternative fuels displace conventional, high-emitting ones. If this displacement turns out to be untrue for some modes, CARB may need to re-assess their treatment under the LCFS. 124-49 Cont.

NextGen Urges CARB to Direct More Resources Towards Improving Research Into Indirect Effects of Fuel Production, Especially Indirect Land Use Change

The scientific foundation of the LCFS is Life Cycle Analysis, which is itself, a comparatively new method of analysis. New data and analytical techniques emerge regularly, as well as a better understanding of the strengths and limitations of this technique. Recent authors have suggested that a focus on direct analysis of material and energy flows within the narrowly-described boundaries of a production process (often called "attributional analysis") may overlook many critical impacts and yield an inaccurate assessment of actual emissions.[16] This is especially true with regard to effects that are mediated through domestic or international markets, where production processes may compete for resources in ways that are difficult to accurately characterize. These indirect effects, especially indirect land use change (iLUC), can result in significant emissions, particularly from biofuel production. 124-50

We believe that CARB, and the LCFS Program Staff, have done an excellent job at assessing the full range of extant literature on indirect effects and iLUC and the LCFS is on the cutting edge of regulatory sophistication where this is concerned. We must acknowledge, however, that the literature on indirect effects is far from complete and we cannot rule out the possibility that the current iLUC values used by the LCFS substantially underestimate actual effects.

NextGen urges CARB to dedicate more research support towards a better understanding of domestic and international markets for feedstocks used in low-carbon fuel production. In particular, we feel more attention is necessary to understand indirect effects and cross-product substitutions in the edible and inedible oil and tallow market These fuels comprise the preferred feedstock for biodiesel, renewable diesel and

[16] e.g. Plevin, R. J., Delucchi, M. A. and Creutzig, F. (2014), Using Attributional Life Cycle Assessment to Estimate Climate‐Change Mitigation Benefits Misleads Policy Makers. Journal of Industrial Ecology, 18: 73-83. doi:10.1111/jiec.12074

alternative jet fuel production. If CARB's assessment of indirect effects is inaccurate, the LCFS could be supporting inefficient, or harmful environmental and economic outcomes.

If updated research demonstrates that previous fuel pathways inaccurately assess actual emissions, CARB should adjust existing fuel pathways to match updated data. We recognize that retroactively changing fuel pathway CI scores may impact financial stability of producers of affected fuels and are willing to support a gradual, or phased-in transition to more accurate CI values. A science-based program like the LCFS cannot, however, support credit generation based on inaccurate data indefinitely. 124-50 Cont.

NextGen Suggests CARB Review How the LCFS Assesses Additionality Where Other Policies Change Emissions From a Transportation Fuel System

Additionality, in life cycle analysis, means that effects must have been caused by a particular project, product or process in order for their effects to be considered as a result of that project, product or process. In essence, a change in emissions must be predominantly because a given fuel is used if that fuel is to receive LCFS credits for reducing emissions. Under a comprehensive climate portfolio, like California's, there are likely to be multiple policies affecting emissions of projects, processes or products which are inputs to a transportation fuel. CARB should seek to balance the scientific imperative to base policy on an assessment of emissions under the strongest methodology against the need to create a stable and sufficient incentive for deployment of advanced fuel systems. 124-52

Staff have indicated that at present, they typically allow credit generation to claim benefits from reduced emissions of greenhouse gases for up to 10 years after such emissions would have been controlled by other policies. There is no scientific justification for why emissions should be credited as reductions for 10 years after they would have, in fact, been reduced. We urge CARB to re-evaluate such provisions and determine whether so long a period of crediting after the emissions have been controlled is, in fact, necessary to support critical investment in low-carbon fuels. We urge Staff to err on the side of science when making decisions relating to additionality.

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NextGen Urges CARB to Improve Transparency Relating to Details of Method 2 Pathway Applications

CARB publishes all Method 2 pathway applications for fuels seeking to generate LCFS credits, however, in most cases the critical quantitative information is redacted as confidential business information (CBI). We understand that CARB has an obligation to protect the CBI of pathway applicants, however this protection removes so much data that it is functionally impossible for independent researchers to verify claims made by applicants. The extensive redaction also reduces the value of Method 2 pathway applications to researchers and limits the evolution of research in this space. 124-53

We urge CARB to improve the transparency of Method 2 applications where possible. We ask Staff to review current protocols related to redacting CBI to determine whether more transparency is possible without improperly exposing CBI. Even if there are no legally feasible changes to the treatment of any particular pathway, we ask CARB to explore whether aggregated average quantitative data from similar pathways could be released. This would protect the CBI of any particular company, but provide a better lens for researchers to see real-world behavior of advanced clean fuel production systems, which will accelerate relevant research into this space and help better calibrate models against real data.

A Strong LCFS Positions California for Success

CARB has an opportunity to build upon many years of success by extending a strong LCFS program through 2030 and building upon the foundation it has laid. California has an opportunity to continue its leadership in climate, clean energy and transportation policy for years to come. 124-54

We again thank CARB and the LCFS Program Staff for the opportunity to comment on this critical rulemaking and for their effort, thoughtfulness, transparency and receptiveness to feedback through this process. Their work has produced a strong and set of proposals for the LCFS program and with a few amendments, as discussed in this letter, we are confident that the LCFS can achieve its full potential to deliver cleaner air, innovative technology and sustainable transportation. We look forward to continued engagement on this matter as it continues through the rulemaking process.

Thank you,

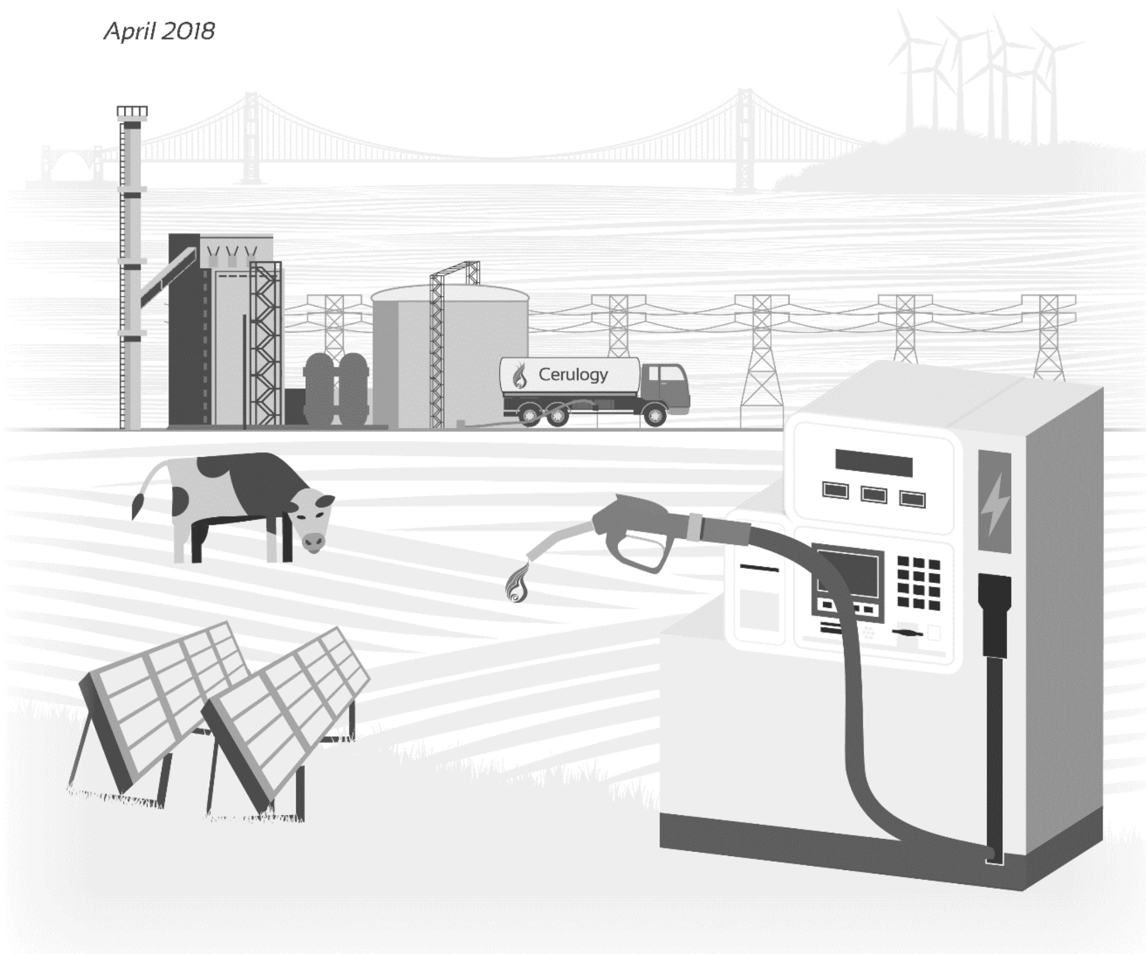
Colin Murphy Ph.D.
Transportation Policy Manager
NextGen California

California's Clean Fuel Future: Update

Assessing Achievable Fuel Carbon Intensity Reductions Through 2030

Dr Chris Malins

April 2018



Note on update

This report is an update to the report *California's Clean Fuel Future - Assessing Achievable Fuel Carbon Intensity Reductions Through 2030* (Malins, 2018), published in March 2018. This update report uses the same underlying modeling framework, but reflects a number of adjustments to fuel supply and methodological assumptions, informed by feedback received on the first report. Readers should note that while the names given to scenarios remain the same as in the March report, there are changes to credit generation in all of the scenarios reflecting the modeling updates. These amendments and the resulting revised model results are documented in the body of this report, and a list of amendments to the model is included in **Error! Reference source not found.**.

Acknowledgements

This project was kindly supported by the NextGen Policy Center, Ceres and the Union of Concerned Scientists (UCS). We would like to thank Colin Murphy of NextGen for input and discussions, Stephanie Searle for support and kind permission to develop the International Council on Clean Transportation's Pacific Coast low carbon fuel supply model for this project, and Ryan Schuchard for sharing CALSTART's analysis of potential deployment of medium and heavy duty electric vehicles. We are grateful for additional input we received from Jeremy Martin (UCS), Julie Witcover (UC Davis), Andy Wunder (Ceres), Dan Lashof (NextGen), Aaron Isenstadt (ICCT), Jason Barbose (UCS), Ryan Lamberg (National Biodiesel Board) and the LCFS team at the California Air Resources Board. Cover by Jane Robertson Design.

Executive Summary

California has long been a global leader in climate policy. Starting with the passage of AB 32 in 2006, California has adopted a strong portfolio of measures to reduce emissions from its economy. Transportation, and the production of transportation fuels, are responsible for over 40% of the state's total carbon emissions. Reducing transportation's climate impact will be critical if the state is to meet its long-term climate goals, and reducing emissions from fuels is a critical part of this effort. California's Low Carbon Fuel Standard (LCFS) is the primary tool the state has to do this.

The LCFS requires fuel suppliers in California to reduce the carbon intensity of their fuels – the amount of carbon pollution per unit of energy – by 10% by 2020, from a 2010 baseline. Fuel providers have a variety of options for compliance. Currently, most credits for the program are generated by blending in lower-carbon liquid fuels into the existing fuel supply. Fuel suppliers can generate credits by taking action themselves, or purchase emission reduction credits from other low-carbon fuel producers. Since it took effect in 2011, the Air Resources Board reports that the LCFS has reduced emissions by the equivalent of over 30 million tonnes of carbon dioxide.

The California Air Resources Board (CARB) is now looking to the future. CARB staff have proposed to extend the program past its current 2020 sunset to 2030, and to increase the carbon intensity reduction target to 20% over that time, along with adjusting the compliance schedule in the interim. They have requested input from stakeholders regarding potential fuel supplies which might allow the state to meet this higher target. In this context, this updated[1] report evaluates potential LCFS credit supplies through 2030, by building on a modeling framework developed for a 2015 report: *Potential Low Carbon Fuel Supply to the Pacific Coast Region of North America*. The model from the 2015 report was updated to reflect recent developments in low carbon fuel technology, policy and markets. The fundamental question is: how much low-carbon fuel can be expected to be available in California over the 2020-2030 period? In addition, the new work evaluates the effect of over or under-performance by key fuel pathways, relative to their projections, on total credit supply.

The analysis shows that given reasonably expected rates of deployment for low carbon fuel technologies, there will be ample supplies of low-carbon transportation fuel to attain CARB's 20% proposal, and that a higher target would likely be achievable. Under the moderate assumptions modeled in the *Steady Progress* scenario a 2030 target of over 21.5% would be feasible. Under the more optimistic assumptions included in the *High Performance* scenario, a 2030 target over 26% would be attainable, while scenarios that include optimistic scenarios in a single area would allow a target of 23-25% to be achieved by 2030. Even in the case of some credit generation pathways under-performing expectations, a 20% carbon intensity reduction in 2030 remains achievable.

Under or over-performance of any fuel pathway is not solely a matter of luck or dependent on future energy markets; the development of most of these pathways will be influenced by policy

[1] See note on page 2.

decisions available to regulators now. Through a combination of clear, long-term targets under the LCFS and the use of complementary policy instruments, the eventual outcome of the program can be directed towards the upper range of its potential.

It is important to note that the model used in this study does not consider market effects, nor is it meant to predict actual market behavior. It assesses potential fuel availability, based on current research, and generally makes moderate assumptions about future availability of low-carbon fuels. In addition, potentially significant credit generation pathways that have not yet been included in the regulation have been omitted due to a lack of adequate data or uncertainty about future regulatory design.

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Introduction

California's Low Carbon Fuel Standard (LCFS)[2] is one of the world's most sophisticated and successful policy instruments for supporting carbon intensity reduction in the transportation sector. Established in 2007, the regulation requires that by 2020 the carbon intensity of regulated transportation fuels in California should have been reduced by 10% on average compared to the 2010 baseline. The California LCFS is the first transportation fuel regulation in the world to directly link the value of different transportation energy carriers to a lifecycle assessment of their greenhouse gas performance, and the California Air Resources Board (ARB) has undertaken pioneering lifecycle analysis across a range of fuels and issues to make the implementation of LCFS possible.

Despite the ambitious nature of the targets set by the LCFS, and political and legal opposition to the standard from some stakeholder groups, implementation to date has been successful. By 2015, alternative fuels met 8.1% of Californian transportation energy demand (Yeh & Witcover, 2016), and the California Air Resources Board reports that the program generated 33 million tonnes of carbon emissions reduction credits[3] between the start of 2011 and third quarter of 2017, and a significant credit bank has been built up over this period.

The LCFS is one of a portfolio of measures developed by the California ARB to support compliance with the California Global Warming Solutions Act (AB 32, Chapter 488 Statutes of 2006), which set a target for the state to reduce greenhouse gas (GHG) emissions to 1990 levels by 2020. As 2020 approaches, attention turns naturally to what can be achieved in the next decade. The California Legislature passed SB 32 (Chapter 249, Statutes of 2016), which set a target of a 40% reduction in GHG emissions by 2030 and extended the regulatory authority which authorizes the LCFS.

In March 2018 the California ARB posted draft rulemaking documents[4] ahead of a hearing scheduled for 27 April 2018, in which an adjusted and extended LCFS compliance schedule to 2030 is proposed (see Figure 1). The proposed adjustments set a 2030 requirement for a 20% GHG intensity reduction, with a steady increase in stringency of 1.25% each year starting with the existing 2018 standard. The new schedule, while more ambitious over the full term of the program, delays until 2022 the implementation of the 10% standard currently scheduled for 2020.

[2] Cf. https://www.arb.ca.gov/fuels/lcfs/lcfs.htm, http://www.energy.ca.gov/low_carbon_fuel_standard/

[3] https://www.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm

[4] https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm

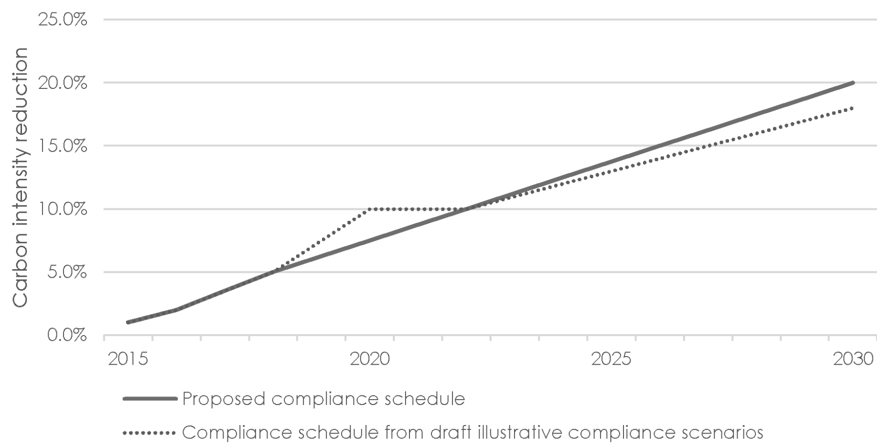

Figure 1 Proposed compliance schedule for the LCFS to 2030

As part of the process of assessing reasonable 2030 targets for the LCFS, ARB staff are actively soliciting feedback from stakeholders. In this context, this report, which is an update to a report first published at the end of March 2018, uses a fuel supply modeling framework developed by the International Council on Clean Transportation (ICCT) and E4tech (Malins et al., 2015) to develop California low carbon fuel and greenhouse gas emissions reduction scenarios for 2030. As detailed further in the rest of this report, these scenarios show that given moderate assumptions on future low carbon fuel supply it would be possible to deliver compliance with 2030 targets more ambitious than the 20% reduction in the current proposal. The moderate, "*Steady Progress*" scenario shows a carbon intensity reduction of 21% by 2030 is possible. The *"High Performance"* scenario – which assumes accelerated technology deployment - delivers a carbon intensity reduction of over 26% by 2030.

Modeling framework

The modeling presented in this report is based on an updated version of the low carbon fuel supply model documented by Malins et al. (2015). The model, originally used to assess the potential to comply with a Pacific Coast low carbon fuel standard, couples vehicle stock turnover and energy demand modeling with low carbon fuel supply modeling. The vehicle stock and energy demand model is based on VISION 2014, with some elements updated for this report using data from VISION 2017.[5]

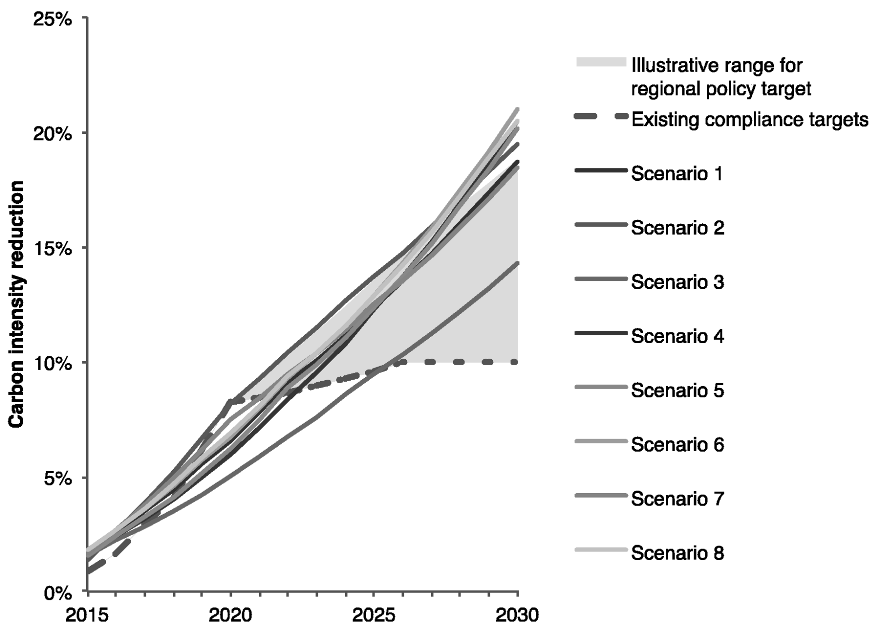

Figure 2 Pacific Coast carbon intensity reduction scenarios from Malins et al. (2015)

[5] https://www.anl.gov/energy-systems/project/vision-model

In the previous study, scenarios were presented showing a range of 2030 transportation fuel carbon intensity reductions for the Pacific region (California, Oregon, Washington and British Columbia) from 14 to 21% (Figure 2).

The underlying model is documented extensively in Malins et al. (2015), and the reader is advised to refer to that report to obtain a more detailed description of the model. For this report, the model has been recalibrated to the California market, and various updates have been made to reflect more recent data. Changes to the low carbon fuel supply assessment are detailed below, and model adjustments are documented in Annex A. Further adjustments that have been made for the updated version of this report are additionally documented in Annex D.

The model used in this report is not a compliance model – there are no internal feedback mechanisms by which the model can respond to credit supply shortages or surpluses, and no attempt is made to model LCFS credit prices. Rather, it is a credit supply model, detailing the number of LCFS credits (and hence the level of emissions reduction) that can be generated given certain assumptions about vehicle sales and the availability of various fuel options and carbon intensity reduction technologies. In the real world, it is intrinsic to the design of the LCFS that suppliers are expected to take measures to increase the supply of LCFS credits if confronted with a shortfall against compliance targets, or to reduce the supply of LCFS credits if confronted with an over-supplied market.

Low carbon fuel supply assessment update

The results presented in Malins et al. (2015) included credits generated by a range of compliance options including first generation biofuels, second generation biofuels, electric drive vehicles, natural gas vehicles. For some compliance options, such as the use of natural gas and the supply of electricity for electric drive vehicles, the main limitation on the rate of compliance credit generation is the capacity of the vehicle fleet to use those fuels. For others, such as first generation ethanol and biodiesel, the rate of credit generation is limited by the amount of the fuel that can be used at existing standard blend limits, but also by the carbon intensity performance of the fuels being produced. For others, notably drop-in biofuels such as hydrotreated vegetable oil and cellulosic renewable diesel, the main limitation on credit generation is the supply of the fuel to the California market.[6] Assessing potential delivery of carbon intensity reductions therefore requires an assessment along three axes: potential fuel supply; potential fuel demand; and potential fuel carbon intensity.

The cases used as building blocks for low carbon fuel supply scenarios in Malins et al. (2015) reflect various assumptions about development of these fuel pathways to 2030, and are the starting point for the analysis in this report. However, the California fuel market has different characteristics than the Pacific market, and there have been developments in the vehicle and fuel market since 2015 that have been taken into account for new modeling. The ARB has released two sets of illustrative compliance modeling (California Air Resources Board, 2017c, 2018a)[7] containing fuel supply and credit generation scenarios for the LCFS to 2030. Several key issues are discussed in the sections below, while a full review of model amendments is provided in Annex A.

Electric vehicle fleet development

Passenger vehicles

Since 2015, the electric vehicle market has continued to expand. California's 2017 Climate Change Scoping Plan (California Air Resources Board, 2017a) anticipates that there will be 4.2

[6] It should also be recognized that total national and global supply of some fuels is limited by the sustainable availability of the feedstocks required.

[7] The second illustrative compliance scenarios were released part way through this project, and therefore both documents are referred to in this report.

million electric drive vehicles (BEVs, PHEVs and FCVs, but excluding HEVs) by 2030. This compares to a slightly lower 4 million in the whole Pacific region by that year in the 'medium' case in Malins et al. (2015). California's advanced clean cars mid-term review is consistent with the 2017 Scoping Plan, recommending that California should, "Strengthen the ZEV program for 2026 and subsequent model years" (California Air Resources Board, 2017b). The mid-term review notes that, "Since the adoption of the 2018 through 2025 model year standards, manufacturers have been exceeding the annual requirements of the ZEV regulation." As of March 2018, Veloz reported that there had been 380,000 cumulative sales of ZEVs in California.[8]

On 26 January 2018 the Governor of California signed an executive order setting a target of 5 million electric vehicles in the state by 2030 (Office of the Governor of California, 2018) and proposing additional policy actions to deliver this, including an increased appropriation for ZEV rebates. The baseline EV deployment scenario in the model has been updated to reflect the reported 2016 ZEV fleet and deliver 5 million ZEVs by 2030 in line with the Governor's target. The model is calibrated to deliver 2 million ZEVs by 2025, which is considered consistent with the 5 million anticipated in 2030. Sales of ZEVs are divided between battery electric vehicles (BEVs), plug-in hybrid vehicles (PHEVs) and fuel cell vehicles (FCVs) in line with the 'high demand' case for ZEVs outlined by Bahrenian et al. (2017).

Medium and heavy duty vehicles

Electric drive medium and heavy duty commercial vehicles are not internally modeled by VISION 2014. Given, however, that they are expected to deliver significant numbers of LCFS credits by 2030, it was considered important to add them to the supply model. For the baseline assumptions, annual sales of MD/HD electric vehicles from 2024 to 2030 were taken from the proposed regulatory schedule for a medium- and heavy-duty electric vehicle sales mandate detailed by Mobile Source Control Division (2017), as shown in Table 2. Sales from 2020 to 2022 are assumed to grow gradually towards the proposed 2023 mandate level.

[8] http://www.veloz.org/

Table 2 Number of MD/HD electric vehicle sales assumed in the modeling baseline

Year	% of CA sales	Vehicle sales
2020	0.56%	300
2021	1.11%	600
2022	1.67%	900
2023	2.50%	1,350
2024	5.00%	2,700
2025	7.00%	3,780
2026	8.50%	4,590
2027	10.00%	5,400
2028	10.00%	5,400
2029	13.00%	7,020
2030	15.00%	8,100

For the *MD/HD breakthrough* scenario, an accelerated deployment rate was modeled based on analysis by CALSTART, which is detailed in Annex B.

Given that these vehicles are not natively modeled in VISION 2014, credit generation was estimated by assuming the amount of diesel displaced is proportional to the number of vehicles in the medium and heavy duty fleets respectively. For the baseline it is assumed that EV sales are split 50:50 between medium and heavy duty vehicles. For the *MD/HD breakthrough* scenario, it is assumed that 27% of sales are medium duty and the rest heavy duty, based on the data from CALSTART. In order to be conservative, it was assumed that each electric vehicle would displace only 90% of the energy consumption of the average diesel fueled MD/HD vehicle.

Electricity mix

The electricity mix assumption have been updated from the assumptions used in Malins et al. (2015). The 2030 California electricity mix is modeled based on carbon intensity data from CA-GREET (California Air Resources Board, 2016) and on grid mix data from preliminary RESOLVE modeling by the California Public Utilities Commission (California Public Utilities Commission, 2017). In the baseline case, the 2030 grid mix is based on the 42 mmt reference case, with 60% renewables in 2030, plus 9% from hydro and nuclear power. For the scenarios with faster electricity decarbonization (the *High ZEV* and *High Performance* scenarios), the 2030 grid mix is based on the 30 mmt reference case, with 65% renewables.

Time-of-use dependent charging ('smart charging') credits

The 2018 proposed regulatory order for the Low Carbon Fuel Standard introduces new options for accounting for electricity use in electric vehicles. One of these is to allow a lower carbon intensity to be reported for vehicles charged during times of the day (9 am – 4 pm) in which curtailment of renewable electricity generation is most likely. In the new modeling, the effective carbon intensity of the electricity mix has been adjusted to reflect potential take up of this reporting option.

Projected charging profiles in California Energy Commission (2018) show an average of 20.9% of charging happening in the relevant part of the day. Given that there is no significant downside to fuel supply equipment operators in reporting time of charging in order to become eligible to take advantage of time of use charging Cis, we assume that uptake of this option will be significant. The model assumes that by 2020, 40% of EV charging will be done through time-monitored EV charging rates that allow time-of-use specific Cis to be taken advantage of (20% signing up in 2019 and a further 20% in 2020). This is set equal to the fraction of clean vehicle rebate recipients already using an EV charging rate, according to survey data posted by the California Clean Vehicle Rebate Project[9]. The model assumes that the fraction of EVs being charged with the option to report the time-of-use CI increases linearly to 80% by 2030. The fraction of charging assumed to occur in the 9 am - 4 pm window is multiplied by the fraction of users able to report time-of-use specific CIs to calculate the overall impact of smart charging on the reportable electricity CI in each year.

The calculation of time-of-use Cis is dependent on rates of curtailment and on the carbon intensity of non-curtailed electricity that is used in each time window. Both of these may change over time, and will be reassessed in future by the Air Resources Board. In the current modeling, it has been assumed that the time-of use Cis documented in the proposed regulation order remain constant to 2030, but this assumption warrants further assessment in future work.

Renewable electricity charging credits

The second option available to allow EV charging to be reported at a lower carbon intensity than the default is to allow electricity supplied through a green tariff program to be reported as lower carbon intensity on a book and claim basis. In order for a lower CI to be claimed, electricity must be generated by equipment owned by or under contract to the pathway applicant, must be demonstrably additional to renewable electricity used to demonstrate compliance with Renewable Portfolio Standards and any renewability certificates must be retired and not used to demonstrate compliance with any other environmental regulation (excepting the federal Renewable Fuel Standard).

[9] https://cleanvehiclerebate.org/eng/survey-dashboard/ev

As in the case of time-of-use charging provisions, there is a clear advantage to registering EV charging through green tariffs to generate LCFS credits, and therefore it seems reasonable to assume significant take up of this provision. Based on analysis by the NextGen Policy Centre[10] the model has been updated to assume that 16% of EV charging is done through green tariffs by 2020 (with 8% adoption in 2019 and a further 8% in 2020). The rate of adoption is then assumed to grow to cover 33% of charging by 2030. This is based on an expectation that take up will be very-strong for non-residential charging stations, and that both use of fast charging stations using green tariffs and of residential adoption of green EV tariffs will continue to increase to 2030.

Renewable Natural Gas

The medium case presented in Malins et al. (2015) assumed that Pacific region transportation could access a renewable gas supply of up to 445 million diesel gallons equivalent (DGEs), and that up to 75% of total natural gas consumed in transportation may be renewable. The ARB illustrative compliance scenarios for 2030 (California Air Resources Board, 2017c, 2018a) assume that 90-100% of natural gas supply to Californian transportation will be renewable by 2020, and show 320 million diesel gallons equivalent (DGE) of natural gas consumption by 2030.

Parker, Williams, Dominguez-Faus, & Scheitrum (2017) provide an assessment of technical and economic potential of renewable natural gas generation in California itself. Of a total identified technical potential of 600 million DGE from landfills, dairies, wastewater treatment and anaerobic digestion of municipal waste, it is found that three quarters (450 million DGE) could be delivered economically given the value of existing incentives. The use of mass balance accounting for renewable natural gas supply allows resources from across the country to generate LCFS credits, but this work shows that in principle all of California's renewable natural gas demand (given a baseline scenario for the number of natural gas powered vehicles) could be generated in-state.

Following the lead of the illustrative compliance scenarios, the previous limit on maximum fractional contribution of renewable natural gas to overall natural gas supply has been removed from the model. The number of natural gas vehicles in the fleet has been better calibrated to the California market, and the maximum potential renewable gas supply scenarios are unchanged from Malins et al. (2015). The assumed carbon intensity of renewable natural gas has been adjusted to reflect the weighted average of dairy RNG (which is assigned a negative carbon intensity) and other sources of RNG. The potential supply of lowest carbon intensity dairy natural gas is limited to the supply level assumed by California Air Resources Board (2017c).

[10] Private communication, April 2018.

The model is very close to California Air Resources Board (2017c, 2018a) in the amount of natural gas consumption anticipated in the baseline, at 317 million DGE. This is also close to the 310 million DGE given in the 'high demand' scenario by Bahrenian et al. (2017).

Renewable hydrogen

Malins et al. (2015) assumed that the carbon intensity of the hydrogen supply for fuel cell vehicles would reduce gradually to 2030 as an increasing share is sourced from renewable sources, and in particular from electrolysis with zero carbon electricity, with the EER adjusted CI falling from 53 to 47 gCO_2e/MJ by 2030. The CARB illustrative compliance scenarios, however, assume that all hydrogen supplied to fuel cells under the LCFS will come from steam methane reforming of renewable natural gas. This reflects the allowance of book and claim accounting to demonstrate the renewable origin of biogas used for hydrogen production, which makes it unlikely that any significant volume of hydrogen will need to be reported as natural gas derived. For the new modeling, we have adopted CARBs CI assumption of 40 gCO_2e/MJ throughout the modeled period.

Development of the cellulosic biofuel industry

Malins et al. (2015) included a review of the state of the cellulosic biofuel industry in the United States, and a deployment model for cellulosic biofuel production capacity based on work by Plevin, Mishra, & Parker (2014).

In the three years since the previous report, the cellulosic biofuel industry has suffered further setbacks in the U.S. and elsewhere in the world. Notably, several commercial scale cellulosic plants have struggled to debottleneck and have failed to demonstrate commercial production at close to nameplate capacities. The Dupont plant in Nevada[11] IA, Abengoa plant in Hugoton[12] KS, Poet-DSM plant at Emmetsburg[13] IA, and Biochemtex plant in Italy[14] have all experienced major setbacks in delivering target rates of cellulosic ethanol production, with all except the Poet plant reportedly mothballed at the current time.

Given that the rates of capacity expansion anticipated by Malins et al. (2015) have not been realized in the intervening period, the database of expected cellulosic biofuel capacity in the

[11] https://www.desmoinesregister.com/story/money/agriculture/2017/11/02/dowdupont-shutters-nevada-cellulosic-ethanol-plant-looks-buyer/824606001/
[12] http://www.biofuelsdigest.com/bdigest/2016/07/18/abengoas-hugoton-cellulosic-ethanol-project-goes-on-the-block/
[13] http://www.argusleader.com/story/news/2017/04/28/poet-accuses-engineering-company-failure-quest-cellulosic-ethanol/100993870/
[14] https://renewablesnow.com/news/mossi-ghisolfi-ponders-sale-of-biofuels-operations-in-italy-report-586538/

model has been revised to reflect a reduced number of projects, and to adjust expected dates for planned facilities to become operational. This has the overall effect of making the model less optimistic about rates of cellulosic biofuel production expansion in all cases when compared to the earlier work.

As in Malins et al. (2015), it is assumed that, due to the LCFS, California represents the most attractive market for cellulosic biofuel consumption in the U.S., and therefore that a large fraction of overall supply available to California. For the baseline case, that fraction is 60% of total cellulosic fuel produced.

Biodiesel and NOx

In July 2017, ARB approved the additive VESTA 1000 to reduce NOx emissions from blends of diesel with fatty acid methyl ester (FAME) biodiesel, certifying that a B20 blend with 0.3% VESTA 1000 emitted less NOx and particulates in testing than the reference diesel fuel. The availability of this additive removes a regulatory barrier to the use of higher blends of biodiesel in California. The model has been updated to assume a higher starting blend of biodiesel for California (reflecting the implied blend for 2016 documented in the draft illustrative compliance scenario). Higher average biodiesel blends than those used in Malins et al. (2015) are allowed in 2020 and 2030 - of B10 and B15 respectively, with a gradual blend increase through the 2020s.

Hydrotreated vegetable oil renewable diesel

Potential volumes of renewable diesel from the hydrotreated vegetable oil (HVO) pathway have been increased compared to those modeled in Malins et al. (2015). This reflects that higher volumes of supply have been recorded to California than were anticipated for the whole Pacific region in the previous work, with a 2017 supply of 350 million gallons anticipated for 2017 by California Air Resources Board (2018a), double the medium scenario modeled by Malins et al. (2015). Assumed supply in the updated model is set to peak at 950 million gallons of distillate substitutes (renewable diesel plus renewable jet) in 2023, remain at that level until 2025, and then reduce to 750 million gallons supplied in 2030 as credit generation by other compliance pathways such as ZEVs accelerates. This compares to a total 2023 supply of 950 to 1,250 million gallons of distillate substitutes assumed in the illustrative compliance scenarios from ARB (California Air Resources Board, 2018a), and an average 2030 supply across all scenarios of 1,230 million gallons . These volumes of HVO supply remain well within the expected global production capacity as documented by Malins et al. (2015), and given the strong market signal from LCFS credits it is reasonable to anticipate that California will receive a significant fraction of global supply.

While fuel production capacity need not limit the supply of these volumes of renewable diesel to the California market, it is important to note that there may be sustainability implications of large-scale use of by-product, residual and waste lipids (such as used cooking oils, animal fats and distillers' corn oil) that are not captured under the existing lifecycle accounting conventions within the LCFS. This possibility is discussed in more detail by ICF International (2015). In this study, the sensitivity of credit generation to the possibility of changing the methodology for accounting carbon savings from these fuels is explored in one of the sensitivity scenarios by applying an indicative value for indirect emissions from using these materials. This is discussed in more detail below in the explanation of that sensitivity case.

New compliance credit generating options

Since 2015, several additional compliance options have been or are expected to be introduced to the LCFS that were not reflected in Malins et al. (2015). These are:

- Refinery investment credits;
- Refinery renewable hydrogen credits;
- Low complexity/low energy use refinery credits;
- Aviation low carbon fuel credits.

These are in addition to existing crediting opportunities for innovative crude oil extraction and for non-road transportation electricity consumption.

Refinery renewable hydrogen credits

For the modeling baseline, the 'medium' case for renewable hydrogen consumption from Stillwater Associates (2018) is used, giving 750,000 tonnes of emissions reductions a year by 2030. In the *Clean Refineries* scenario, this rate of credit generation is increased to 1.9 million tonnes a year, in line with the high scenario in Stillwater Associates (2018), which is based on assumed rate of credit generation for this compliance option in California Air Resources Board (2017c).

Refinery investment credits

The baseline model assumptions on availability of refinery investment credits are based on the 'medium' case documented by Stillwater Associates (2018). In the *Clean Refineries* scenario, the availability of refinery investment credits is based on the 'high' case in that same report. The analysis by Stillwater Associates (2018) assessed potential for credits from the use of renewable or low-CI electricity, from low-CI process energy, and from electrification at refineries. It also considers the potential for CCS at refineries – this is discussed in more detail below in the section on CCS below.

Low complexity/low energy use refinery credits

This option is assumed to be a minor credit generator. It is assumed that 70,000 tonnes of credits are generated per year, in line with California Air Resources Board (2017c).

Aviation fuel

Advanced alternative fuels for aviation are chemically similar to drop-in substitute diesel fuels (HVO and cellulosic renewable diesel) that are already included in the model. Within the logic of the supply model, increased use of these fuels for aviation will result in reduced availability for road diesel. Given that the per-gallon LCFS credits available for displacing diesel and jet fuel are very similar, we have not introduced explicit modeling of the use of these fuels in aviation – it is assumed that for a given level of fuel supply, the mode to which these fuels are supplied will make only a marginal difference to overall compliance credit generation. It is possible that opening up additional markets for renewable mid-distillate fuels will encourage development of production capacity. Increased market draw for substitute distillate fuels is not explicitly dealt with in the cellulosic fuel production module. A rapid expansion of the use of renewable jet fuel by aviation could therefore result in larger volumes of substitute distillate fuels being produced than is anticipated in the existing model baseline.

Carbon capture and sequestration

The model has also been updated to allow credit generation by the introduction of carbon capture and storage for ethanol and petroleum refineries.

In the model baseline, it is assumed that CCS is introduced only for ethanol refineries in California itself. This baseline assumption is intended to be conservative against the full potential for CCS in the ethanol industry, and to partly reflect the possibility that California may introduce complementary incentives (e.g. through the cap and trade program) that would not be available for out-of-state ethanol refineries.

Based on McCoy (2016) it is assumed that retro-fitted CCS at ethanol refineries can reduce lifecycle carbon intensity of ethanol by 32 gCO_2e/MJ. Given 218 million gallons of ethanol production in California, this results in 567,000 tonnes per year of credit generation. It is assumed that capture capacity grows linearly from nothing in 2021 to full adoption by 2028. For the *Clean Refineries* and *High Performance* scenarios, it is assumed that CCS is also implemented at all starch-ethanol refineries supplying fuel to California by 2030, with credit generation again growing linearly from nothing in 2021 to full implementation by 2028.

The baseline scenario also includes 365 thousand tonnes of CCS at refineries by 2030, based on Stillwater Associates (2018) with a linear growth from no credit generation in 2021 to full implementation by 2028.

Table 3 CO_2 emissions recorded for steam methane reforming in California

Facility	CO_2 Emissions (tonnes/yr)
Shell Martinez Refinery	816,174
Valero Benicia Refinery	948,212
Tesoro Golden Eagle Refinery	562,646
Chevron Richmond Refinery	1,334,862
Air Products & Chemicals Martinez (Shell)	723,983
Air Products & Chemicals Martinez (Tesoro)	264,024
Air Liquide Rodeo (Shell)	769,835
Shell Rodeo	111,304
Total	**5,531,040**

For the *Clean Refineries* scenario only, it is also assumed that CCS is implemented for all Californian steam methane reforming (SMR) units in the oil refining sector at Northern California refineries.[15] Soltani, Rosen, & Dincer (2014) suggest implementing carbon capture after the syngas shift phase of the SMR process. If optimized for CCS, finding that up to 65% of process CO_2 could be captured at this stage. H2A modeling from the DOE[16] anticipates a higher potential CO_2 recovery rate of

[15] The northern refineries have better access to geologically suitable carbon sequestration sites.

[16] https://www.hydrogen.energy.gov/h2a_prod_studies.html

81% capture by CCS. The EPA facility level emissions inventory[17] identifies eight relevant facilities in California with combined CO_2 emissions of 5.5 million tonnes per year (Table 3). Assuming 60% CO_2 capture, installing CCS for all these facilities would deliver 3.3 million tonnes per year of credits.

The *Clean Refineries* scenario reflects the highest level of CCS ambition modeled for this report, but it is worth noting that there is potential in principle that a successful scaling up of CCS technologies could have a much broader impact on industry in California, and deliver very large numbers of LCFS eligible credits, particularly if post-combustion capture of CO_2 from flue gas is widely deployed. The combination of the LCFS credit and the federal 45Q tax credit could provide well over 125 \$/tCO_2e of value to CO_2 abatement through CCS at the refinery, a value proposition that some commentators believe may prove quite compelling. Capturing 70% of all CO_2 emitted by Bay Area refineries alone could deliver 11 million tonnes of emission reductions, in which case refinery CCS would be comparable to electric vehicles as a source of greenhouse gas emissions reductions. Currently, credit generation by refineries through CCS is limited to 5% of total deficit generation, and this limit would rapidly be met in the event of such widespread adoption of CCS. Should deployment reach that stage, it would be appropriate to consider whether the limit could be relaxed, ideally in concert with a proportionate increase in ambition of the LCFS compliance schedule in order for the program to continue supporting additional deployment of these technologies. Further detail on the underlying assessment of CCS opportunities is available in Murphy and Martin (2018).

Transportation energy demand

In Malins et al. (2015), vehicle miles travelled (VMT) assumptions were based on the data included within VISION 2014. For this modeling, VMT assumptions for passenger vehicles have been updated in the central case to assume a 6.9% average statewide reduction from 2015 to 2030, reflecting the opportunities for urban VMT reduction in California detailed by ICF (2016).

New vehicle efficiency assumptions are based on data from VISION 2017, which reflect improvements required by corporate average fuel economy (CAFE) standards for 2025. For instance, gasoline internal combustion engine (ICE) fuel economy increases by 32% for cars and 47% for light trucks between 2015 and 2025, while efficiency of new gasoline hybrids increases by 24% for cars and 38% for light trucks. As 2030 standards have not yet been set, the model assumes no significant efficiency improvement from 2025 to 2030, which makes the overall predicted transportation energy demand reduction more conservative than it otherwise would be. The model does not consider any potential feedback between increased ZEV share and reduced fuel economy for other vehicles.

[17] https://ghgdata.epa.gov/ghgp/main.do

The modeling assumptions used result in an overall transportation energy demand reduction of 19-22% from 2016 to 2030 in the model, depending on scenario. In comparison, the ARB illustrative compliance scenarios with a 20% compliance requirement for 2030 include a total transportation energy demand reduction of between 23% and 26% in the low demand case, and between 8% and 11% in the high demand case (California Air Resources Board, 2018a). The modeling here is therefore slightly conservative on potential overall transportation energy demand reductions compared to the low demand illustrative compliance scenarios, but optimistic compared to the high demand scenarios.

Potential indirect emissions of using lipids and fats characterized as by-products, residues or wastes for biofuel feedstock

Currently, within the LCFS no indirect emissions are attributed to biofuels produced from several feedstock materials considered as wastes and residues, in particular biodiesel and renewable diesel produced from used cooking oils/greases, animal fats, and distillers' corn oil. Similar assumptions are made by other regulatory biofuel support mechanisms such as the Renewable Fuel Standard, and in Europe the Renewable Energy Directive. This assumption does not take into account the fact that these lower-value lipids and fats already have economic utilization, in particular in the animal feed industry and in niche oleochemical applications (cf. ICF International, 2015; Malins, 2017; Searle, Pavlenko, El Takriti, & Bitnere, 2017). It is likely that giving full consideration to the market consequences of largescale diversion of these resources would result in the identification of non-negligible indirect emissions resulting from the sourcing of replacement materials for existing uses, somewhat analogous to the indirect land use change emissions associated with land-based biofuel production. In the absence of detailed assessments of these indirect emissions consequences due to displacement in U.S. markets, a scenario is included below in which the indirect land use change emissions value for soy biodiesel is used as a proxy for an appropriate calculated value. This scenario is intended as an illustration of the impact on compliance of potential future adjustments to the LCFS carbon accounting rules to more accurately represent the full lifecycle implications of using these types of material as biofuel feedstock.

This is the only potential methodological adjustment to the LCFS lifecycle assessment that has been considered in this report, which reflects requests by the ARB for additional modeling evaluation on this question. It is important to recognize that as new data becomes available and LCA science develops, there may be changes introduced to the lifecycle values attributed to other fuel pathways, and that these could result in either lower or higher rates of credit generation.

Credit Generation Opportunities Not Modeled

While we have attempted to comprehensively cover likely credit generation under a likely re-adopted LCFS, there are some potential credit generation pathways which we do not explicitly consider which could increase the potential credit supply. These un-modeled pathways may be thought of as a buffer that would expand potential LCFS credit supply beyond what is estimated

Some stakeholders have also requested an LCFS credit pathway for electric bicycles and scooters, which would, if implemented, add a small amount of additional credits to the existing market. Similarly, there are prototype electric aircraft entering the market which could, in the future, be eligible for LCFS credit generation, and credits for zero-emission transportation refrigeration units (TRUs) have been suggested, but are not modeled here. As discussed above, there is also a chance that the emergence of alternative jet fuels could lead to a net increase in the availability of low-carbon distillate substitute fuels to the California market, which has not been explicitly modeled here.

Carbon capture and sequestration has only been evaluated in the context of selected refinery operations or ethanol facilities. It is possible that this under-estimates the potential of CCS to generate credits from other pathways, such as electrical generation units where the resulting energy is expressly being produced for use as transportation fuel, or from other biofuel production facilities.

Neither the exclusion of these pathways from the modeling, nor their discussion here, should be taken to imply any position on their inclusion in the re-adopted LCFS.

Incremental crude oil deficits

The CARB illustrative compliance scenarios (California Air Resources Board, 2018a) include an assumption on additional deficits generated due to increases in the carbon intensity of the California crude oil supply. The new modeling includes these additional deficits at the rate assumed in the illustrative compliance scenarios.

Low carbon fuel supply scenarios

Understanding the results

In this chapter, the results of ten scenarios for the low carbon fuel supply to California in 2030 are presented. As discussed above and by Malins et al. (2015), the model used here should be understood as a fuel supply model rather than as a compliance model. This is because the model includes no feedback mechanism from the performance against existing or draft compliance targets on the rate of credit generation – credit generation is determined by assumptions about the amount and type of energy supplied. In the real world, suppliers can be expected to take measures to increase the supply of LCFS credits if confronted with a shortfall against compliance targets, or to reduce the supply of LCFS credits if confronted with an over-supplied market.

Where the scenarios below show an annual supply of credits below the draft targets, this should not be taken to imply that fuel suppliers could not potentially take measures to increase short-term credit supply to allow compliance in such a year. Conversely, where the results of a scenario show a large accumulation of extra credits (under the draft compliance scenario), this should not be taken to imply that we would expect suppliers to keep growing the credit bank indefinitely if the supply of credits exceeds expectations. The rates of credit generation shown in each scenario are implicitly based on an assumption that the LCFS credit value remains significant throughout the period considered. If credit generation was high enough to result in large reductions in credit price, and the compliance schedule was not adjusted, it might be expected that rate of credit generation from some technology options would reduce. In the real LCFS, the credit trading mechanism allows for credit value to adjust to bring overall supply closer to what is needed for compliance, in a way that is not reflected in this model.

The scenarios should therefore rather be understood as a characterization of the number of credits that could be generated under certain technology and deployment assumptions. The comparison to the draft compliance schedule should be considered illustrative rather than predictive.

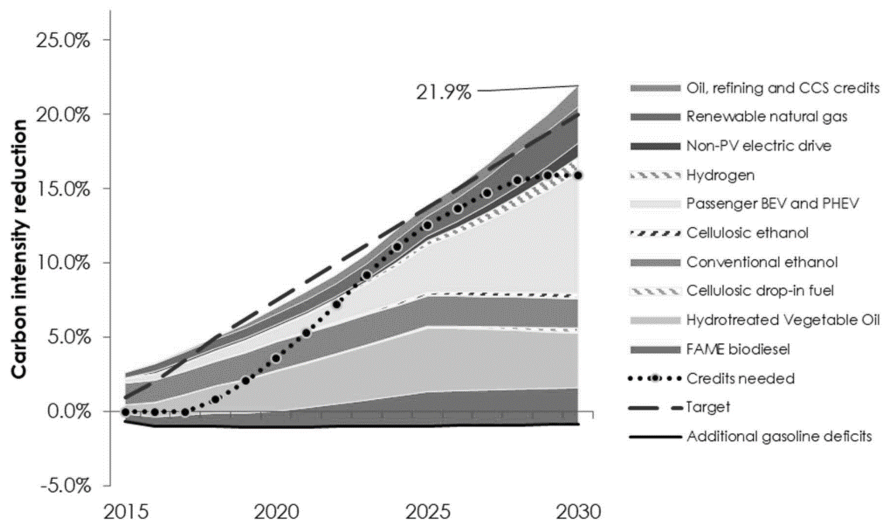

Figure 3 Example of a carbon saving supply chart

For each scenario, two charts and a table are presented. An example of the first type of chart is provided in Figure 3. In these carbon-saving supply charts, a series of 'wedges' stacked one on the other represent the % emissions reductions compared to the California fuel carbon intensity baseline that could be delivered from each compliance option in that scenario. The sum of all of these carbon savings is labeled, this number represents the total carbon intensity reduction achievable by 2030 in each scenario. The wedges shown on the chart are as follows:

- Conventional ethanol – ethanol from non-cellulosic feedstocks such as corn, sugarcane and molasses and supplied with gasoline either as an E10 or E85 blend.
- FAME biodiesel – fatty acid methyl ester biodiesel supplied in a blend with diesel.
- Hydrotreated Vegetable Oil – renewable distillate fuels from hydrotreating lipid feedstocks that can be blended with diesel or jet at any rate as 'drop-in' fuels.
- Cellulosic ethanol – ethanol produced from cellulosic feedstocks and supplied with gasoline either as an E10 or E85 blend.

- Cellulosic drop-in fuel – fuels produced using biomass-to-liquids technologies from cellulosic feedstocks that can be blended with diesel, jet or gasoline at any rate as 'drop-in' fuels.
- Passenger BEV and PHEV – electricity supplied for use by battery electric and plug-in hybrid ZEVs in the passenger vehicle sector.
- Non-PV electric drive - electricity supplied for use by medium and heavy duty vehicles, rail and forklifts.
- Hydrogen – hydrogen supplied for use in fuel cell electric drive vehicles
- Renewable natural gas – biomethane supplied for passenger and heavy duty vehicles[18]
- Oil and refining credits – carbon savings generated by innovative crude extraction, refinery improvements and carbon capture and sequestration at petroleum refineries.
- Additional gasoline deficits – additional deficits generated in the gasoline pool because the carbon intensity of CARBOB (California Reformulated Gasoline Blendstock for Oxygenate Blending) is higher than the carbon intensity of the gasoline baseline.

It should be understood that this graph shows carbon savings relative to the baseline, not carbon savings relative to the annual compliance schedule. The bottom of the chart starts slightly below zero, reflecting the number of additional deficits expected to be generated due to a slight increase in the carbon intensity of gasoline as compared to the baseline. The emissions reductions generated compared to the 2010 baseline are then layered on, one compliance option after another.

The final wedge, 'oil refining and CCS credits' is an aggregate of several credit generation pathways. These pathways include credits from carbon capture and storage (at both ethanol and petroleum refineries) and additional credits generated by refineries and upstream in the oil supply chain.

Two lines are plotted over the wedge chart. The dashed line shows the draft compliance schedule, peaking with a 20% carbon intensity reduction target in 2030. This is included in the chart to allow the carbon savings generated in that scenario to be compared with the number that would be needed each year for the draft compliance targets. It should again be remembered that the model used is a *supply* model, not a *compliance* model, and therefore there is no LCFS credit price in the model and no feedback in the model on rate of credit generation from the state of the credit market.

The second line, which is dotted, shows the carbon savings that would need to be generated in any given year to meet the draft target, given the number of credits or deficits that are carried over from the previous year. Where there is a positive balance of banked credits, the dotted line

[18] All natural gas supplied for transportation is assumed to be renewable from 2018 onward.

is below the dashed line (compliance can be delivered partly using banked credits). In the case that a deficit is carried over, the dotted line runs above the dashed line, showing the additional savings needed to pay off the deficits previously incurred. Interest is charged in the model on any deficits carried from year to year.

The second type of chart, showing net credits generated each year, (an example is given in Figure 4) is identical in form to a chart include in the CARB draft illustrative compliance scenario spreadsheet (California Air Resources Board, 2017c). It shows the net number of credits or deficits that would be generated each year given the modeled fuel supply (red bars), and the accumulated credit or deficit bank that would be associated with the modeled fuel supply if delivered under the draft compliance targets (blue area). Key results from each scenario are also presented in an associated table in each section.

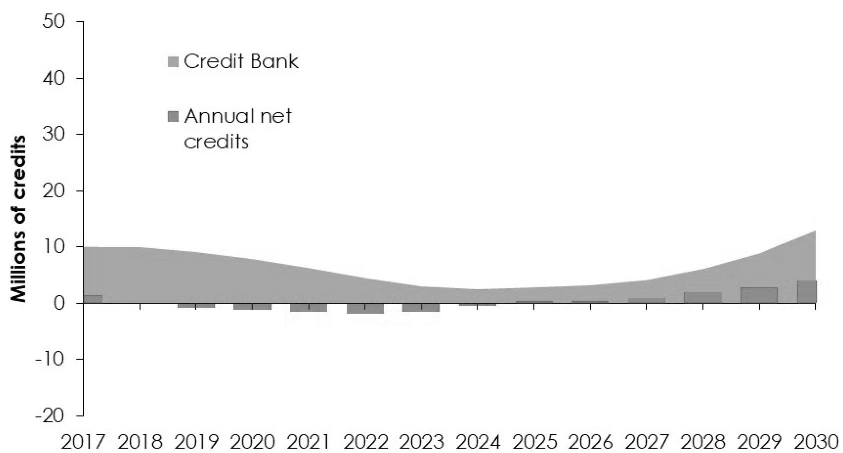

Figure 4 Example credit bank chart

Main scenarios

First, two primary scenarios are presented. In the first, the *'Steady Progress'* scenario, deployment of the various credit generation options develops at a baseline rate that is considered to reflect a reasonable expectation given the current state of technology development portfolio of incentives expected to be available to operators in California and in the U.S more widely. In the second, the *'High Performance'* scenario, it is assumed that several technologies develop more quickly than in the *Steady Progress* case and thus more credit generation would be achievable. In the next section, further sensitivity scenarios are detailed.

Steady Progress

In this scenario, the carbon intensity reduction delivered by 2030 is 21.7%, approaching two percentage points above the draft compliance schedule. Steady progress continues in decarbonization of transportation across the board. Deployment of ZEVs meets the Governor's target of 5 million by 2030, there is gradual progress in commercialization of advanced biofuels, the average carbon intensity of first generation biofuels decreases, and it is assumed that mass balance accounting allows all natural gas supplied for transportation in California to be counted as renewable, utilizing a combination of in-state and out-of-state renewable natural gas supplies.

In the *Steady Progress* scenario, annual consumption of electricity for transportation reaches 18,650 GWh. This is marginally above the 18,000 GWh shown in the high demand scenario by the CEC *Transportation Energy Demand Forecast, 2018-2030* (Bahrenian et al., 2017), reflecting the increased ambition for passenger EV deployment under the Governor's target. Annual consumption of renewable natural gas reaches 310 million gallons diesel equivalent, about the same as the high demand case in Bahrenian et al. (2017), which also reaches 310 million gallons diesel equivalent in 2030.

Consumption of distillate-substitute biofuels, biodiesel and renewable diesel/jet[19], also increases in this scenario. From about 400 million gallons in 2016, by 2030 total demand reaches 1.35 billion gallons (600 million gallons of biodiesel blended at B15, and 900 million gallons of renewable diesel or jet fuel). These 2030 volumes are somewhat below those in the CARB illustrative compliance scenarios for a 20% carbon intensity reduction target (1.6 to 2.5 billion gallons in 2030, including alternative jet fuel). Higher volumes could potentially be made available by more rapid growth of cellulosic drop-in fuel production, or by increased supply of hydrotreated vegetable oils.

Total ethanol consumption falls from 1.6 to 1.1 billion gallons, limited by the blend wall (E10)[20]. Cellulosic ethanol production and consumption increases modestly to 120 million gallons by 2030, and starch ethanol (corn and sorghum) remains the primary source, but continues a trend of reducing carbon intensity including the roll out of carbon capture and storage to California

[19] Including distillates from cellulosic biomass-to-liquids as well as hydrotreated vegetable oil.

[20] A 'high alcohol' scenario in which E85 consumption grows more aggressively is discussed below.

ethanol refineries. A further 30 million gallons of cellulosic biofuel are supplied as drop-in diesel, gasoline and jet fuel, reflecting only modest modeled growth in cellulosic biomass-to-liquids technologies.

Figure 5 shows the contribution of various credit generating technologies to achieving compliance with the draft targets. In the very near term, HVO, biodiesel and conventional ethanol remain the largest credit generators. Moving into the 2020s, however, the greenhouse gas emissions reduction delivered by electricity increase dramatically, as does the generation of credits from renewable natural gas, and by refinery improvements and carbon capture and storage (grouped into 'other credits' in the figure).

There is a drawdown of the credit bank between now and 2026, but from 2027 onwards credit generation starts to exceed modeled annual compliance requirements. As shown in Figure 6, from this point on a significant credit bank starts to build up, reaching 9.5 million by 2030 (Table 4). This suggests that a more stringent compliance trajectory for the final few years to 2030 would be deliverable given these fuel supply assumptions.

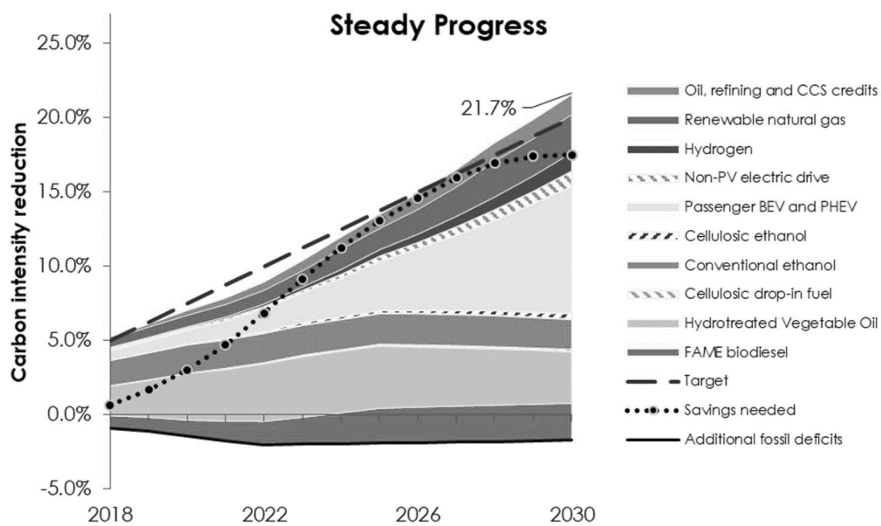

Figure 5 Carbon savings delivered in the *Steady Progress* scenario

This strong end-of-decade performance is partly explained by the non-linear growth in consumption of electricity for transportation as the ZEV fleet grows. As can be seen in Figure 5, by 2030 passenger electric vehicles are the largest single credit generating category.

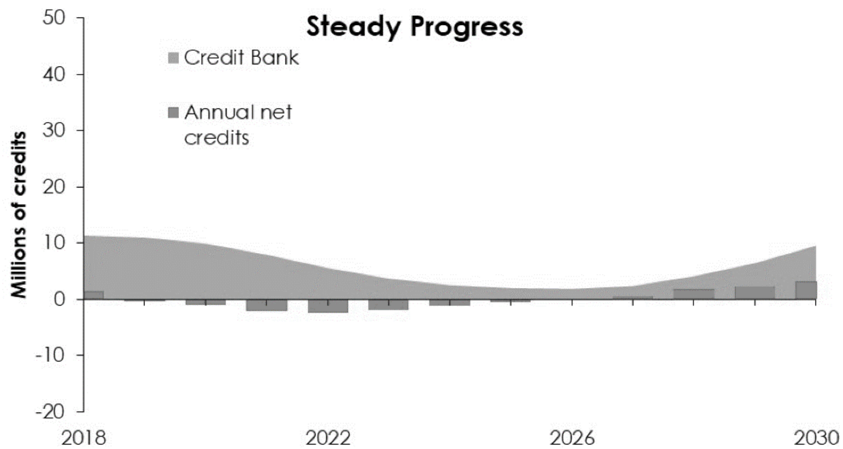

Figure 6 **Credit bank evolution for *Steady Progress* scenario under draft compliance schedule**

Table 4 Overview of results in the *Steady Progress* scenario

	2020	2025	2030
Credit generation by light duty ZEVs (million tCO2e)	1.9	5.9	13.5
Credit generation by cellulosic biofuels (million tCO2e)	0.2	0.6	0.8
Credit generation by HVO and biodiesel (million tCO2e)	8.6	11.1	8.6
Credit generation by renewable natural gas (million tCO2e)	1.3	2.3	4.2
Credit generation by oil extraction and refining, CCS and other electrification (million tCO2e)	1.1	2.7	4.8
Cumulative credit generation since 2018 (million tCO2e)	44.6	157.0	318.1
Annual credit generation (million tCO2e)	16.8	26.5	36.1
Banked credits at year end (million tCO2e)	9.9	2.0	9.5
% CI reduction	7.1%	13.6%	21.7%

Additional details of credit generation in *Steady Progress* are provided in Annex C.

High Performance

This scenario represents the case in which the supply of LCFS credits is significantly enhanced by accelerated technology deployment (as compared to *Steady Progress*) across several credit generation options simultaneously. The technology deployment rate assumptions fall between the Steady Progress case and the even faster deployment rates considered in the technology-specific sensitivity cases below. The accelerated technology deployment assumptions allow for significantly larger carbon intensity reductions to be delivered by 2030 than in the *Steady Progress* scenario - the *High Performance* scenario delivers a carbon intensity reduction of 26.2%, four percentage points higher than in *Steady Progress*. Specifically the *High Performance* scenario differs from *Steady Progress* by having more aggressive deployment assumptions on cellulosic fuels, passenger ZEVs, heavy duty natural gas vehicles, and on carbon capture at ethanol refineries and green hydrogen use at petroleum refineries.

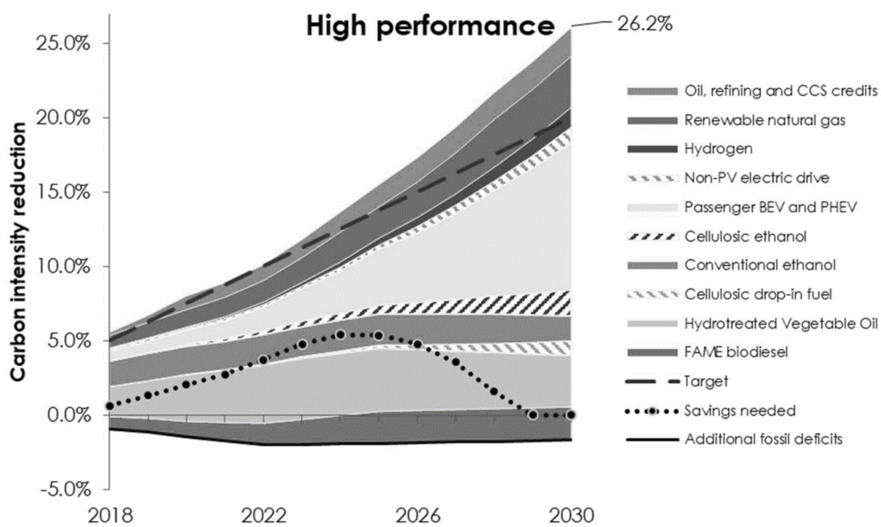

Figure 7 Carbon savings delivered under the *High Performance* scenario

The passenger ZEV fleet grows to 2.3 million vehicles in 2025, and then exceeds the governor's target, reaching 5.8 million by 2030, with ZEVs, including plug-in hybrids, having reached 76% of sales. As noted below in the discussion of the *High ZEV* case, this remains well below some esimates of the achievable ZEV fleet for 2030 (Southern California Edison, 2017). The larger number of electric vehicles results in the cumulative generation of an additional 10 million tonnes of GHG emissions reduction from passenger ZEVs compared to the *Steady Progress* scenario. The natural gas heavy duty vehicle fleet is doubled in size by 2030 compared to *Steady Progress,* allowing an additional 13 million tonnes of cumulative credits to be generated. Simultaneously, the cellulosic ethanol supply reaches over 500 million gallons while the supply of cellulosic drop-in diesel, gasoline and jet fuel reaches 170 million gallons. Whereas in *Steady Progress it* is assumed that CCS credits for ethanol refineries are generated only by California in-state ethanol producers, in High Performance CCS technology is also adopted by ethanol importers. Finally, whereas in Steady Progress the generation of credits by green hydrogen use in refineries reaches only 750 thousand tonnes a year, in High Performance that rate of generation increases to 1.9 million by 2030 (Stillwater Associates, 2018).

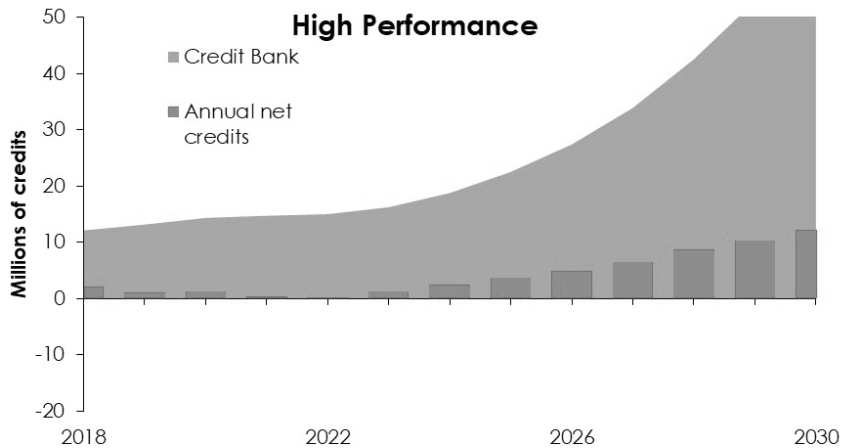

Figure 8 **Credit bank evolution for *High Performance* scenario under draft compliance schedule**

Taken together, these advances allow an additional cumulative 54 million tonnes of credits to be generated by 2030 than in *Steady Progress* (Table 5), with 8 million more credits a year being generated by the end of the period than in *Steady Progress*. As can be seen in Figure 8, when compared to the current draft compliance schedule, these technology deployment successes would result in very large numbers of credits being banked under the proposed compliance schedule. By 2030, more than 10 million tonnes of net credits are being banked annually. Clearly, in practice such large numbers of surplus credits would result in a reduced LCFS credit price, likely reducing the use of some of the credit generation options modeled. Delivering this ambitious rate of decarbonization in practice would therefore require that the compliance schedule be adjusted upwards once the signs of more rapid than expected progress are identified, in order to maintain the role of the credit market in supporting demand for low carbon fuels.

Table 5 Overview of results in the *High Performance* scenario

	2020	2025	2030
Credit generation by light duty ZEVs (million tCO2e)	1.9	6.6	15.8
Credit generation by cellulosic biofuels (million tCO2e)	0.3	1.5	4.3
Credit generation by HVO and biodiesel (million tCO2e)	8.4	10.8	8.2
Credit generation by renewable natural gas (million tCO2e)	2.1	3.4	5.3
Credit generation by oil extraction and refining, CCS and other electrification (million tCO2e)	2.4	3.8	5.9
Additional credits over steady progress (million tCO2e)	2.1	3.8	7.8
Annual credit generation (million tCO2e)	18.9	30.3	43.8
Banked credits at year end (million tCO2e)	14.3	22.5	65.1
% CI reduction	8.1%	15.6%	26.2%

Additional details of credit generation in the *High Performance* scenario are provided in Annex C.

Sensitivity scenarios – strong credit generation

The scenarios presented in this section investigate the sensitivity of the main results to stronger assumptions about the rate of deployment of key individual low carbon technologies, with one assumption adjusted in each case compared to the *Steady Progress* case. The five scenarios consider higher rate of deployment of passenger ZEVs, heavy duty ZEVs, cellulosic biofuels, emissions reductions options at ethanol and petroleum refineries, and in the fifth increased rates of ethanol supply through a higher standard blend and increased use of E85 or other alcohol blends. These scenarios are presented as sensitivity cases to illustrate the effects of credit generation from particularly significant pathways at what we consider to be the higher ends of their likely range. As discussed above, the rate of credit generation in these more optimistic scenarios is not necessarily consistent with the draft compliance schedule – delivering the levels of carbon savings detailed in this section would require not only technological progress, but also ongoing development of the regulatory framework, which would likely need to include tightening the compliance schedule before 2030 in order to support the LCFS credit price.

High ZEV

In this scenario, the governor's target for electric drive vehicle deployment of 5 million vehicles by 2030 is exceeded by even further than was modeled in the *High Performance* scenario. There are 6.7 million ZEVs on the road by 2030, and 90% of new passenger car sales are ZEVs by that year. While this exceeds the Governor's target, it is less than the 7 million vehicles called for in the 'Clean Power and Electrification Pathway' (Southern California Edison, 2017), and the sales rate modeled here is less aggressive to 2025 than projections attributed to Navigant Research and Bloomberg New Energy Finance by California Air Resources Board (2017a).

As one might expect, this accelerated electrification results in strong performance on carbon intensity, with a 24.5% reduction recorded for 2030 (Figure 9). ZEVs are the dominant source of LCFS credits in 2030 in this scenario, accounting for about 50% of total credit generation, and generating 4.7 million tonnes of credits per year more than in *Steady Progress* (Table 6). Annual transportation electricity consumption reaches 24,800 GWh.

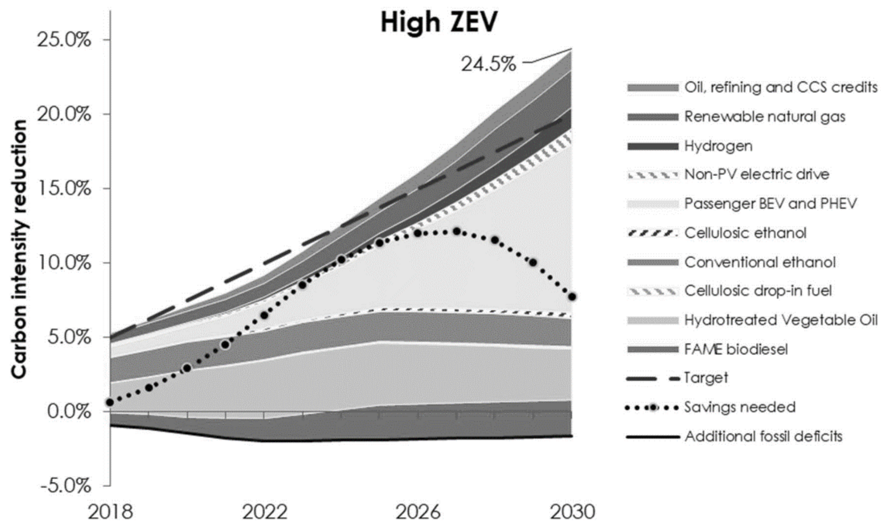

Figure 9 Carbon savings delivered under the *High ZEV* scenario

Even with a very aggressive growth in the ZEV fleet, consumption of liquid fuels remains considerable in 2030, and as can be seen in Figure 9 renewable liquid fuels continue to make an important contribution towards delivering carbon savings. The growth in the ZEV fleet and in electricity use for transportation is not linear, and therefore credit generation in the early part of the 2020s is similar to that in the *Steady Progress* case. From 2025 onward, however, the growth in credit generation results in large credit surpluses and the credit bank reaches about 35 million by 2030.

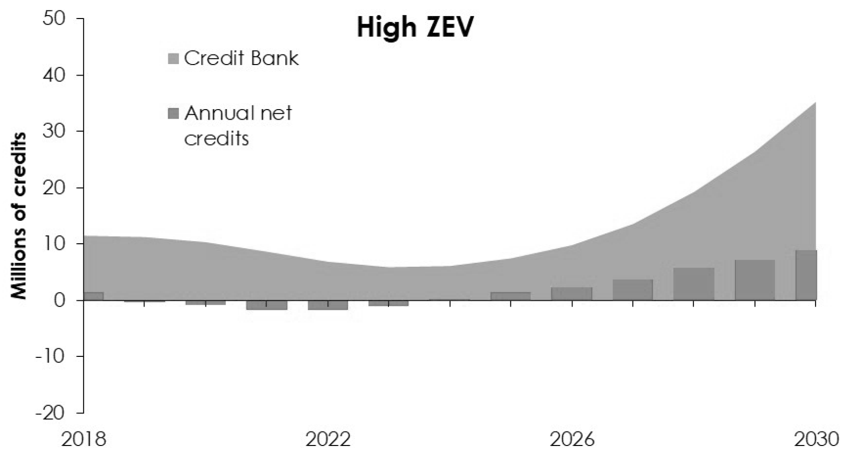

Figure 10 **Credit bank evolution for *High ZEV* scenario under draft compliance schedule**

Table 6 **Overview of results for *High ZEV* scenario**

	2020	2025	2030
Credit generation by light duty ZEVs (million tCO2e)	2.0	7.5	18.2
Credit generation by cellulosic biofuels (million tCO2e)	0.2	0.6	0.8
Credit generation by HVO and biodiesel (million tCO2e)	8.6	11.1	8.6
Credit generation by renewable natural gas (million tCO2e)	1.3	2.3	4.2
Credit generation by oil extraction and refining, CCS and other electrification (million tCO2e)	1.1	2.7	4.8
Additional credits from light duty ZEVs over steady progress (million tCO2e)	0.2	1.6	4.7
Annual credit generation (million tCO2e)	17.0	28.2	41.1
Banked credits at year end (million tCO2e)	10.3	7.5	35.2
% CI reduction	7.2%	14.5%	24.5%

MD/HD Breakthrough

Similar to the high-ZEV case above, this case considers a more rapid deployment of zero emissions vehicle technologies; but rather than considering an accelerated roll out of passenger ZEVs, it assesses an accelerated roll out of medium and heavy duty electric vehicles. Based on analysis by CALSTART (see Annex B) it is assumed that the fleet of MD/HV electric vehicles in California grows to 137 thousand by 2030, three and a half times more than in *Steady Progress*.

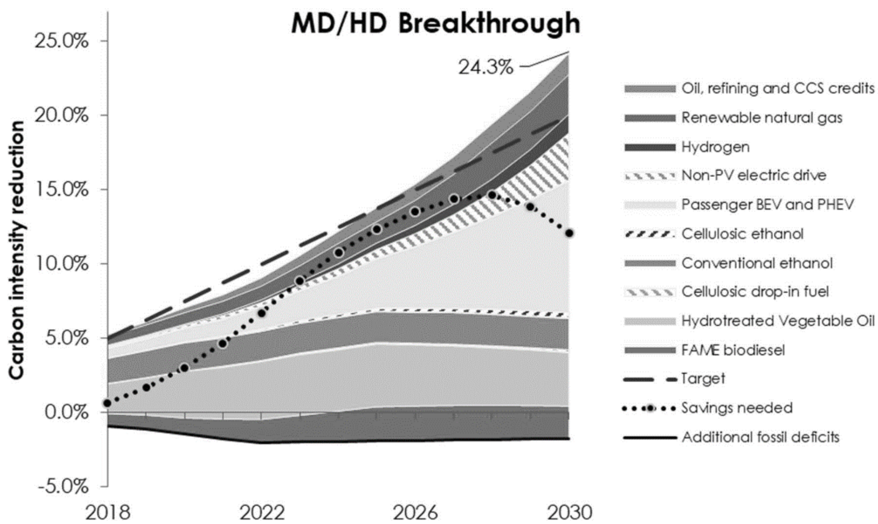

Figure 11 Carbon savings delivered under the *MD/HD Breakthrough* scenario

With this acceleration in MD/HD electrification, electricity supply becomes the largest credit generator in the diesel pool, delivering just under 8 million tonnes per year in 2030 (Figure 11). The credit bank evolution is very similar to that in the *High ZEV* case, with surpluses delivered from 2025 onward growing the bank to 33 million tonnes by the end of the period (Table 7). In 2030, the carbon intensity of the transportation energy mix is reduced by 24.3% compared to the baseline.

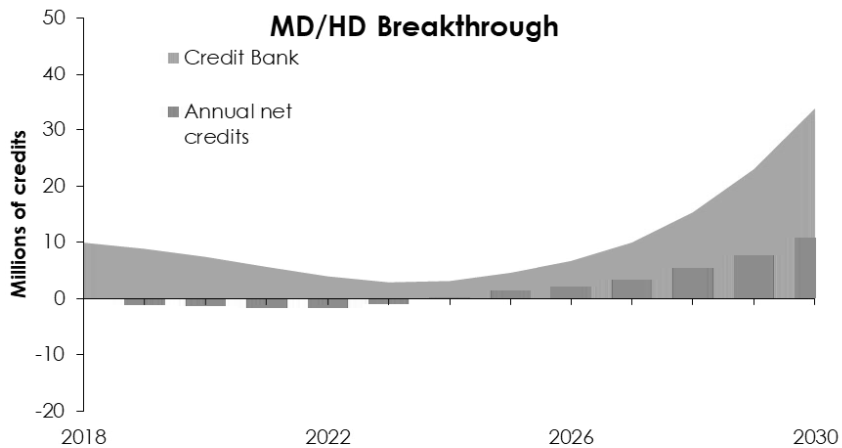

Figure 12 Credit bank evolution for *MD/HD Breakthrough* scenario under draft compliance schedule

Table 7 Overview of results for *MD/HD Breakthrough* scenario

	2020	2025	2030
Credit generation by light duty ZEVs (million tCO2e)	1.9	5.9	13.5
Credit generation by cellulosic biofuels (million tCO2e)	0.2	0.6	0.8
Credit generation by HVO and biodiesel (million tCO2e)	8.6	11.1	8.0
Credit generation by renewable natural gas (million tCO2e)	1.3	2.3	4.2
Credit generation by oil extraction and refining, CCS and other electrification (million tCO2e)	1.2	3.7	11.4
Additional credits from heavy duty ZEVs over steady progress (million tCO2e)	0.1	1.0	6.6
Annual credit generation (million tCO2e)	16.9	27.4	42.1
Banked credits at year end (million tCO2e)	10.0	5.1	32.6
% CI reduction	7.1%	13.9%	24.3%

High Alcohol

In this scenario, the emissions reductions delivered by conventional ethanol are maximized by combining a transition from E10 to E20 as the standard gasoline blend with an increase in the use of E85 fuels by E85 compatible vehicles and increased imports of sugar based ethanol (from sugarcane and molasses). In 2030, 2.4 billion gallons of ethanol are supplied, of which 1.8 billion are starch based, 500 million from sugarcane and molasses based and 120 million are cellulosic. It is assumed, as in the other scenarios, that the carbon intensity for all these ethanol production pathways decreases over time.

As can be seen in Figure 13, the growing ethanol supply results in constant growth of credit generation by conventional ethanol throughout the period assessed. This contrasts with the other scenarios, in which reducing gasoline demand and increased supply of cellulosic ethanol means that conventional ethanol contributes less savings over time.

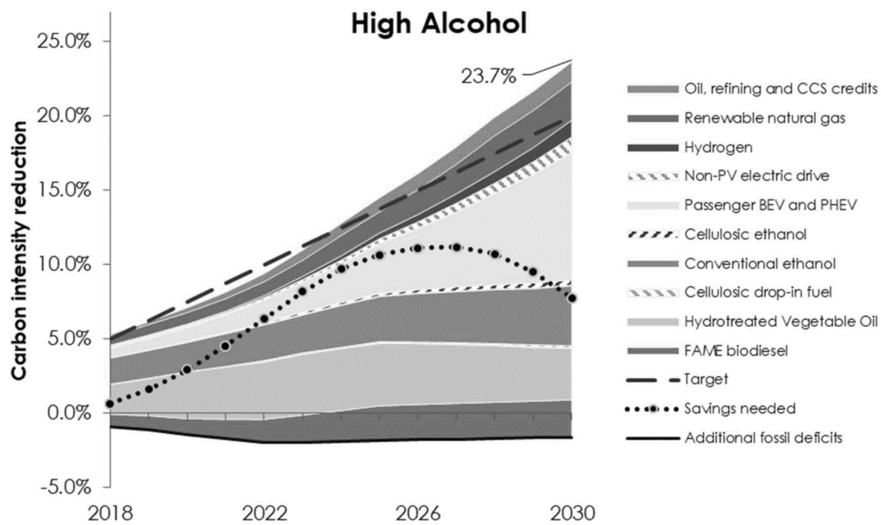

Figure 13 Carbon intensity reductions delivered in the *High Alcohol* scenario

With this larger supply of ethanol, a 23.7% carbon intensity reduction is achieved by 2030. In the modeling, raising the use of ethanol provides additional credits earlier in the compliance period than increasing the supply of electric vehicles. The credit bank grows to 33 million tonnes by 2030 (Table 8).

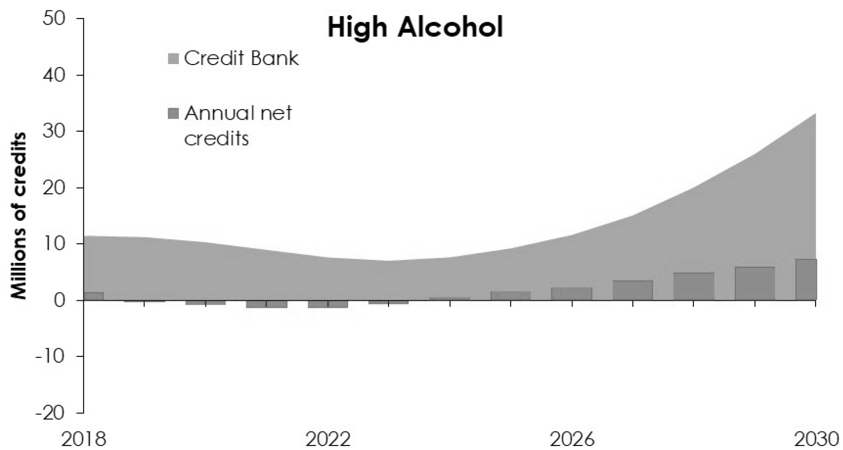

Figure 14 **Credit bank evolution for *High Alcohol* under draft compliance schedule**

Table 8 **Overview of results for *High Alcohol* scenario**

	2020	2025	2030
Credit generation by light duty ZEVs (million tCO2e)	1.9	5.9	13.5
Credit generation by cellulosic biofuels (million tCO2e)	0.2	0.6	0.8
Credit generation by HVO and biodiesel (million tCO2e)	8.6	11.1	8.6
Credit generation by renewable natural gas (million tCO2e)	1.3	2.3	4.2
Credit generation by oil extraction and refining, CCS and other electrification (million tCO2e)	1.1	2.7	4.8
Additional credits from ethanol over steady progress (million tCO2e)	0.2	1.4	0.0
Annual credit generation (million tCO2e)	16.9	27.8	38.1
Banked credits at year end (million tCO2e)	10.3	9.2	33.3
% CI reduction	7.2%	14.6%	23.7%

Cellulosic Breakthrough

In this scenario, all assumptions are the same as in the *Steady Progress* scenario, except that the roll out of cellulosic biofuel production is accelerated within the advanced biofuel deployment model detailed in (Malins et al., 2015). This acceleration is applied to both the cellulosic ethanol industry and the cellulosic drop-in fuels industry. By 2030, California consumes 500 million gallons of cellulosic ethanol and 300 gallons of cellulosic renewable diesel, jet and gasoline. The 2030 supply of cellulosic ethanol matches the supply of starch based ethanol. This represents a dramatic increase in cellulosic fuel supply, but the required growth rate remains modest compared, for instance, to the growth rates that would have been required from 2009 to 2022 to meet the original cellulosic fuel obligation under the Renewable Fuel Standard.

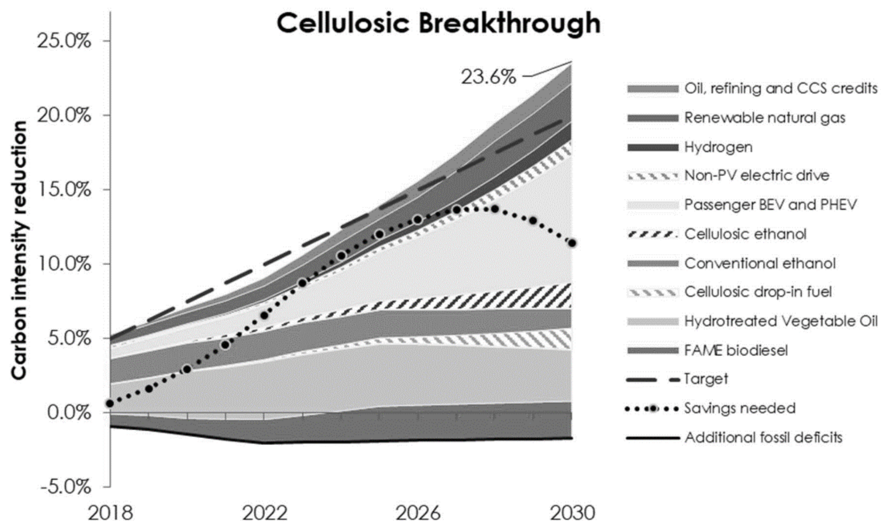

Figure 15 Carbon intensity reductions delivered in the *Cellulosic Breakthrough* scenario

As in the accelerated EV deployment scenarios, significant credit surpluses only start to appear at the back half of the 2020s (Figure 16), but by 2030 a bank of 26 million credits has developed (Table 9). In 2030, a 23.6 %carbon intensity reduction is delivered.

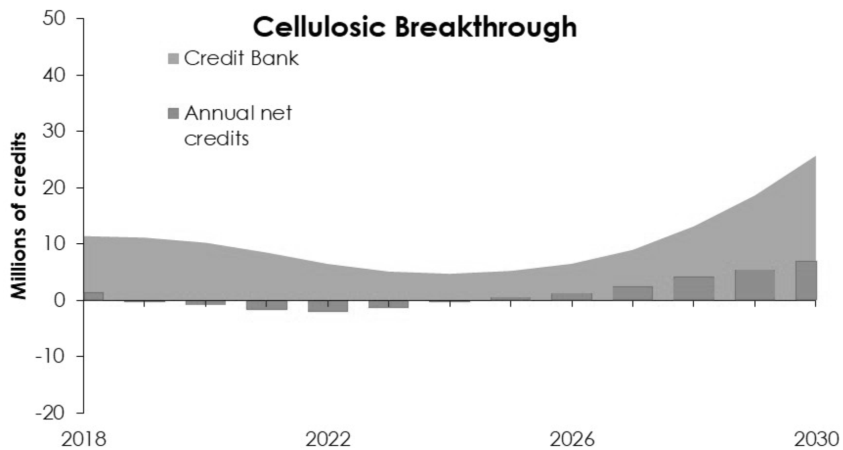

Figure 16 **Credit bank evolution for *Cellulosic Breakthrough* under draft compliance schedule**

Table 9 **Overview of results for *Cellulosic Breakthrough* scenario**

	2020	2025	2030
Credit generation by light duty ZEVs (million tCO2e)	1.9	5.9	13.5
Credit generation by cellulosic biofuels (million tCO2e)	0.4	1.8	4.9
Credit generation by HVO and biodiesel (million tCO2e)	8.6	11.1	8.6
Credit generation by renewable natural gas (million tCO2e)	1.3	2.3	4.2
Credit generation by oil extraction and refining, CCS and other electrification (million tCO2e)	1.1	2.7	4.8
Additional credits from cellulosic biofuel over steady progress (million tCO2e)	0.2	1.2	4.0
Annual credit generation (million tCO2e)	17.0	27.4	39.4
Banked credits at year end (million tCO2e)	10.2	5.2	25.7
% CI reduction	7.2%	14.1%	23.6%

Clean Refineries

In this scenario, additional progress is assumed in the deployment of CCS at both ethanol and hydrogen production units associated with petroleum refineries from 2022 onwards, and also increased use of green hydrogen at petroleum refineries, compared to *Steady Progress*. Whereas in Steady Progress CCS is deployed only to California ethanol refineries, in Clean Refineries it is deployed for all starch ethanol consumed in California, doubling the rate of credit generation compared to *Steady Progress*.

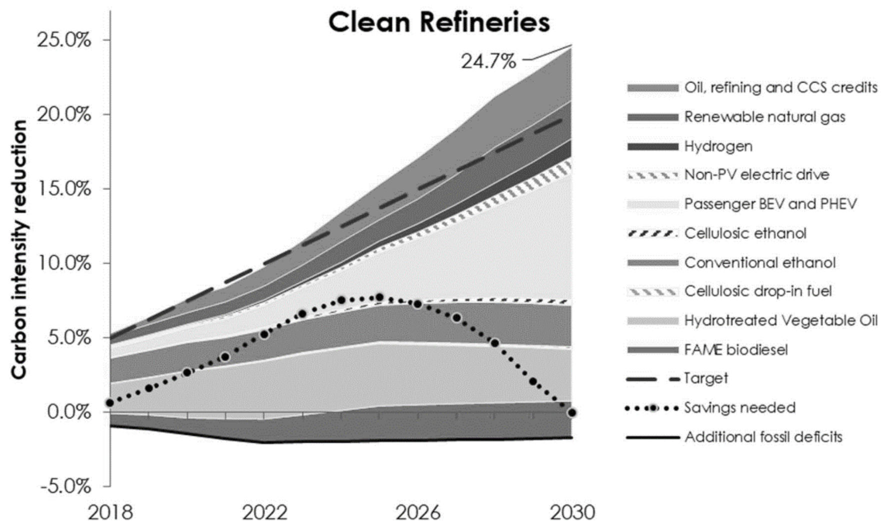

Figure 17 Carbon intensity reductions delivered in the *Clean Refineries* scenario

In this scenario, CCS is also deployed for steam methane reforming (SMR) units in Northern California, with an assumption of 60% CO2 sequestration, delivering an additional 3.3 million tonnes a year of emissions reductions by 2030. Refinery use of renewable hydrogen is also increased, delivering 1.9 million tonnes of savings a year by 2030, reflecting the 'high' scenario from Stillwater Associates (2018). These additional greenhouse gas emissions reductions can be seen in the increased contribution from 'oil, refining and CCS credits' in Figure 17[21].

[21] Remembering that the savings delivered by CCS at ethanol plants are included in the 'oil, refining and CCS credits' category on the figure rather than in the 'conventional ethanol' category.

As detailed in Figure 17, by 2030 a 24.7% carbon intensity reduction is achieved. Annual credit surpluses start to grow from 2024 onward, resulting in significant credit banking when credit generation is compared to the draft compliance schedule (Figure 18), reaching 53 million tonnes of credits by 2030 (Table 10).

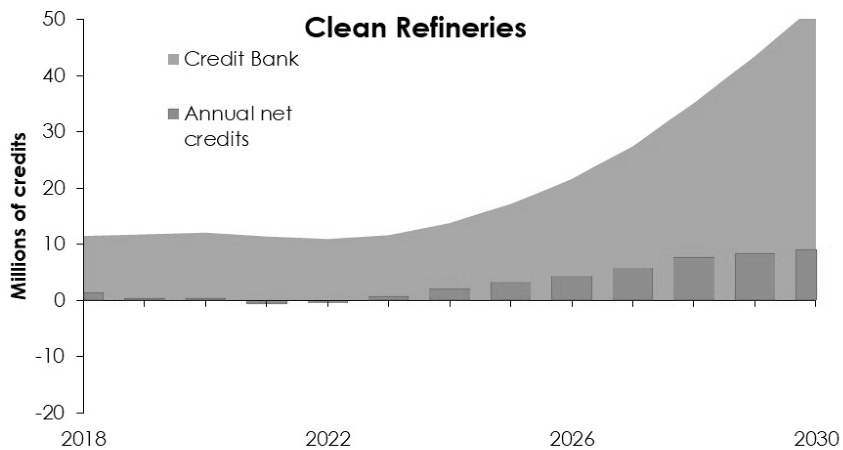

Figure 18 Credit bank evolution for *Clean Refineries* under draft compliance schedule

Table 10 Overview of results for *Clean Refineries* scenario

	2020	2025	2030
Credit generation by light duty ZEVs (million tCO2e)	1.9	5.9	13.5
Credit generation by cellulosic biofuels (million tCO2e)	0.2	0.6	0.8
Credit generation by HVO and biodiesel (million tCO2e)	8.6	11.1	8.6
Credit generation by renewable natural gas (million tCO2e)	1.3	2.3	4.2
Credit generation by oil extraction and refining, CCS and other electrification (million tCO2e)	2.5	5.8	9.3
Additional credits from CCS over steady progress (million tCO2e)	0.0	1.9	3.3
Annual credit generation (million tCO2e)	18.2	30.4	42.1
Banked credits at year end (million tCO2e)	12.1	17.2	52.6
% CI reduction	**7.7%**	**15.4%**	**24.7%**

Sensitivity scenarios – risks to rate of credit generation

In the previous section, five scenarios were presented in which accelerated rate of technology deployment (passenger or heavy duty ZEVs, increased ethanol blending, cellulosic biofuels and refinery emissions reduction) allowed for increase generation of LCFS credits. These positive outcomes resulted in carbon intensity reductions of 23.8-25.2% in 2030, and between 38 and 64 million tonnes of emissions reduction delivered above what is required by the draft compliance schedule.

In this section, in contrast, three cases are presented in which performance would be weaker than that detailed in *Steady Progress.* Firstly, a scenario is presented in which the rate of deployment of key technologies is slower than detailed in the *Steady Progress* scenario. Secondly, a case is considered in which reductions in passenger vehicle VMT proceed more slowly than anticipated in the main modeling, resulting in increased generation of deficits. Finally, a case is presented in which the credit generation performance of liquid diesel fuel substitutes (biodiesel and HVO) is reduced by the inclusion of an indicative term for indirect emissions in the lifecycle carbon intensity values.

Delayed Progress

In this scenario, deployment of key credit generation options is slow compared to the rates assumed in the *Steady Progress* case. Volumes of cellulosic biofuel production remain low, with only 19 million gallons of cellulosic ethanol and 62 million gallons of drop-in cellulosic fuels supplied by 2030. Simultaneously, the deployment of electric vehicles falls short of the Governor's target of 5 million, achieving only the Scoping Plan target of 4.2 million by 2030. In other regards, this scenario matches the *Steady Progress* scenario.

The reduced deployment of these technologies means that, unlike in the *Steady Progress* scenario, annual deficits are generated every year until 2030, at which point the program starts to exceed the compliance schedule as ZEV deployment accelerates.[22] As shown in Figure 20, this results in a complete draw down of the credit bank by 2023, and the creation of a persistent deficit during the late 2020s, reaching over 14 million tonnes. Despite the deficits in intermediate years, the proposed 20% carbon intensity reduction target for 2030 is slightly exceeded, with a 20.2% reduction being delivered.

[22] In the modeling, there is still however a small net credit deficit shown in 2030 due to the interest payments on the deficit bank.

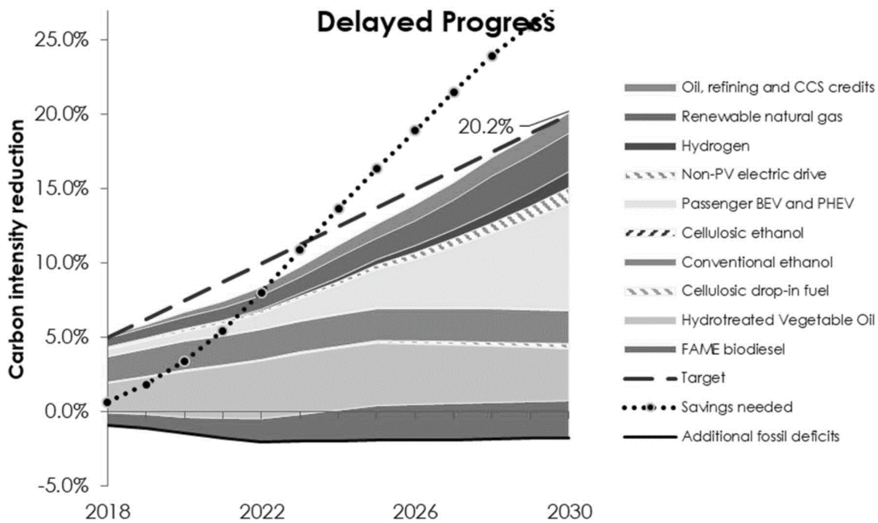

Figure 19 Carbon savings generated in the *Delayed Progress* scenario

It is worth noting that because the *Delayed Progress* scenario is identical to the *Steady Progress* case except on cellulosic biofuel and ZEV deployment, it shares the slight reduction in the supply of HVO renewable diesel and jet after 2025 that is included in *Steady Progress*. Given a tighter credit market, this is one of the credit generation pathways that might potentially be expected to respond in reality with increased fuel supply in those categories.

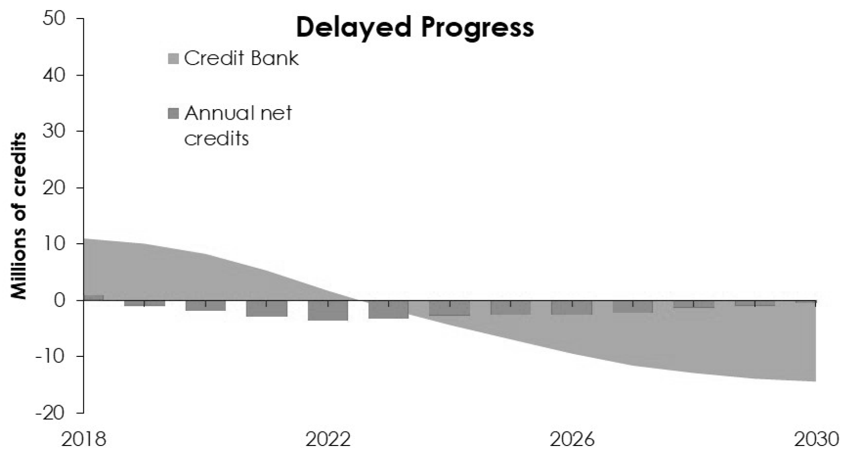

Figure 20 **Credit bank evolution for *Delayed Progress* under draft compliance schedule**

Table 11 **Overview of results in the *Delayed Progress* scenario**

	2020	2025	2030
Credit generation by light duty ZEVs (million tCO2e)	1.2	4.5	11.2
Credit generation by cellulosic biofuels (million tCO2e)	0.2	0.3	0.6
Credit generation by HVO and biodiesel (million tCO2e)	8.6	11.1	8.6
Credit generation by renewable natural gas (million tCO2e)	1.3	2.3	4.2
Credit generation by oil extraction and refining, CCS and other electrification (million tCO2e)	1.1	2.7	4.8
Reduction in credit generation compared to steady progress (million tCO2e)	-0.7	-1.6	-2.5
Annual credit generation (million tCO2e)	16.1	24.9	33.6
Banked credits at year end (million tCO2e)	8.2	-6.9	-14.4
% CI reduction	6.8%	12.7%	20.2%

Higher VMT

This scenario is identical to the *Steady Progress* scenario, except that a more modest reduction in vehicle miles travelled is assumed for passenger vehicles (3.5% instead of 6.9% from 2015 to 2030), resulting in higher overall demand for transportation energy. By 2030, this results in 1.6 million additional annual deficits being generated by fossil fuel use than in *Steady Progress* by 2030 (Table 12).

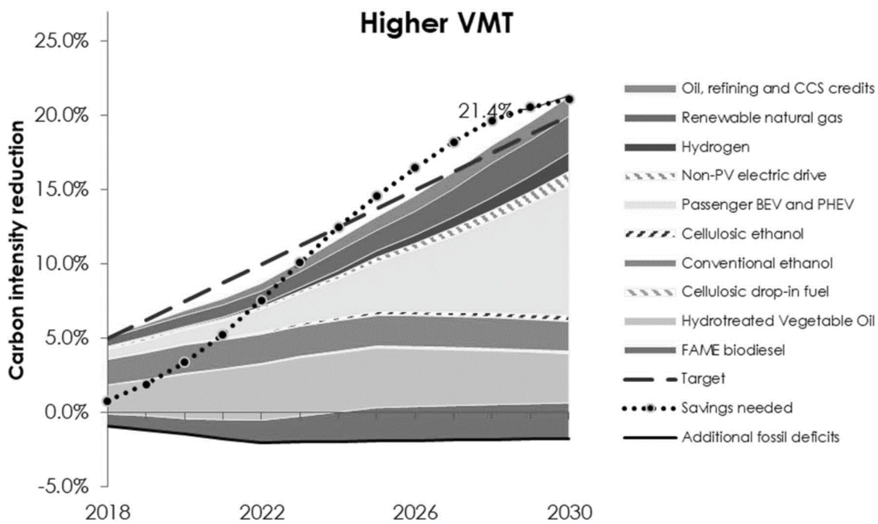

Figure 21 Carbon savings delivered in the scenario with a lower rate of VMT reduction

The higher rate of deficit generation results in a lower overall carbon intensity reduction in 2030 than is achieved in *Steady Progress* (21.4% rather than 21.7%, Figure 21). It also results in an increased rate of credit bank draw-down in the early 2020s, and a slight credit bank deficit from 2024 to 2029. The deficit is cleared, however, and the credit bank eventually grows back to 2 million in 2030 (Table 12).

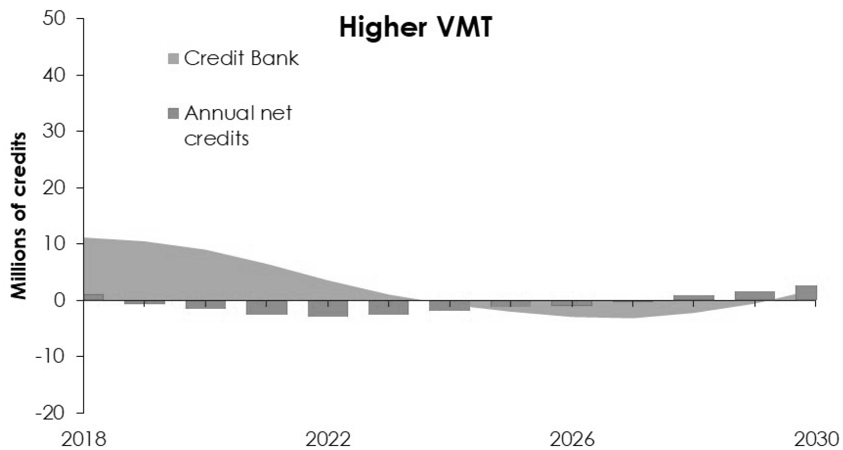

Figure 22 Credit bank evolution for *Higher VMT* under draft compliance schedule

Table 12 Overview of results for *Higher VMT* scenario

	2020	2025	2030
Credit generation by light duty ZEVs (million tCO2e)	1.9	6.2	14.3
Credit generation by cellulosic biofuels (million tCO2e)	0.2	0.6	0.8
Credit generation by HVO and biodiesel (million tCO2e)	8.6	11.2	8.6
Credit generation by renewable natural gas (million tCO2e)	1.3	2.3	4.2
Credit generation by oil extraction and refining, CCS and other electrification (million tCO2e)	1.1	2.7	4.8
Additional deficits due to higher VMT (million tCO2e)	0.7	1.2	1.6
Annual credit generation (million tCO2e)	17.0	27.0	37.2
Banked credits at year end (million tCO2e)	9.0	-2.0	2.0
% CI reduction	7.0%	13.3%	21.4%

Indirect emissions attributed to by-product and residual lipids

As discussed in the body the report above, the current convention under the LCFS is to assume that using by-product or residual lipids such as animal fats and used cooking oils as biofuel feedstock is not associated with any indirect emissions. Given, however, that these are resources that are generally fully utilized in the economy already, for instance as animal feed ingredients, this assumption is likely an over-simplification that results in some indirect emissions effects being excluded from the lifecycle greenhouse gas emissions values for such biofuels. This scenario therefore considers the impact on credit generation of attributing an indicative level of indirect emissions to these lipid feedstocks.

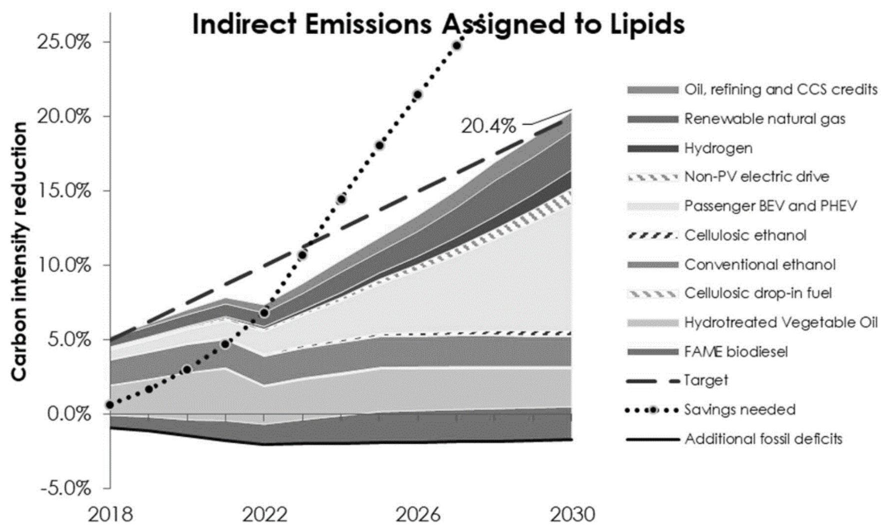

Figure 23 **Carbon intensity reduction scenario with indirect emissions factors applied to used cooking oils and animal fats**

The scenario is identical to the *Steady Progress* scenario, except that it is assumed that additional indirect emissions are attributed to used cooking oil and animal fat based biodiesels, to reflect the need to replace these materials in existing uses and to make the treatment of these feedstocks more comparable to that of crop-based feedstocks that have ILUC factors assigned to them. As discussed above, there is limited analytical work available attempting to quantify these indirect impacts ion the U.S. market. As a proxy for actual assessed indirect emissions values, in this scenario the ILUC emissions of soy biodiesel are assigned to fuels from used cooking oil and from animal fats. This provides an illustration of the potential consequences for LCFS compliance of a change in the accounting regime for these oils. In recognition of the fact that it would take time for analysis to be undertaken of the indirect emissions associated with these fuels, and that it would also take time for any proposed regulatory change to be adopted, it is assumed in the modeling that these additional emissions are not counted until the year 2022 onward. This is evident in Figure 23 where a year on year reduction in total credit generation can be seen between 2021 and 2022.

As one might expect, reducing the credit generation per gallon of these biofuels results in lower credit generation than is seen in the *Steady Progress* case. When the supply of LCFS credits in this scenario is compared to the draft compliance schedule, deficits are generated each year up to 2030 (Figure 24), resulting in the spend-down of the credit bank and eventually in a 23 million tonne net deficit in 2030 (Table 13), although by this time the growth in credit generation through other compliance options has returned the program to meeting the annual compliance schedule, with a 20.4% carbon intensity reduction delivered[23]. Just as it is important to recognize that in the real world the large supply of deficits in the more optimistic scenarios could result in low credit prices, it is important to recognize here that the tightness of the credit market would increase prices, and could well result in additional savings being delivered through the supply of other fuels should such an accounting change be introduced.

[23] As in the *Higher VMT* case, interest payments on the 2029 credit deficit prevent a net credit from being achieved even in 2030 in the modeling.

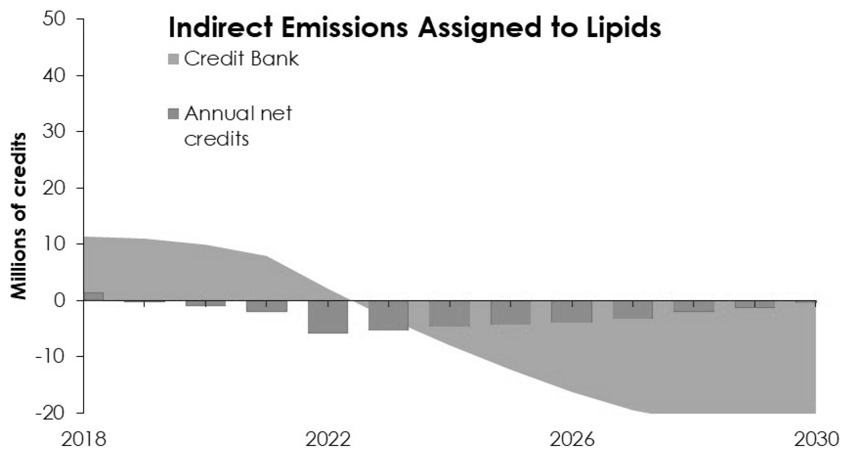

Figure 24 Credit bank evolution for case with indirect emission assigned to lipids under draft compliance schedule

Table 13 Overview of results for scenario with indirect emission assigned to lipids

	2020	2025	2030
Credit generation by light duty ZEVs (million tCO2e)	1.9	5.9	13.5
Credit generation by cellulosic biofuels (million tCO2e)	0.2	0.6	0.8
Credit generation by HVO and biodiesel (million tCO2e)	8.6	7.8	6.1
Credit generation by renewable natural gas (million tCO2e)	1.3	2.3	4.2
Credit generation by oil extraction and refining, CCS and other electrification (million tCO2e)	1.1	2.7	4.8
Reduction in diesel substitute credits compared to steady progress (million tCO2e)	0.0	3.4	2.4
Annual credit generation (million tCO2e)	16.8	23.1	33.6
Banked credits at year end (million tCO2e)	9.9	-12.3	-23.4
% CI reduction	7.1%	12.0%	20.4%

Discussion

The Low Carbon Fuel Standard is a vital plank of California's climate change mitigation efforts, delivering significant reductions in the global warming impact of California's transportation sector. In setting compliance requirements for the next phase of the program up to 2030 the ARB must balance the desire to deliver ambitious rates of decarbonization with the need to set targets that are affordable and achievable.

The Preliminary Draft Proposed Regulation Order for the next phase of the LCFS (California Air Resources Board, 2018b) includes a compliance schedule that would require 20% carbon intensity reductions from California transportation energy by 2030. The draft illustrative compliance scenarios for the LCFS in 2030 that have been released by the ARB (California Air Resources Board, 2017c, 2018a) include scenarios for delivering savings of between 10 and 25% by that time. Meeting the suggested 20% target would require ongoing evolution of California's transportation energy supply, through both electrification of road vehicles and continued expanded use of low carbon fuels. While delivering such a reduction in carbon intensity is not a trivial task, the scenarios presented in this report show that more ambitious targets than those proposed by ARB could be achieved; given reasonable rates of development of low carbon fuel technologies and the appropriate regulatory support, larger carbon emissions reductions could be achieved than would be required under the proposed compliance schedule. The *Steady Progress* scenario presented here shows a pathway to a nearly 22% CI reduction by 2030, while the High Performance case and the optimistic sensitivity cases indicate that with the right support, targets as high as 25% could be deliverable in the 2030 timeframe.

The *Steady Progress* scenario assumes development of alternative and renewable fuel supplies that are generally based on moderate projections from existing literature and targets. Achieving the fuel supply modeled in this scenario would allow the draft compliance schedule to be comfortably met, with significant banked credits to spare. The credit generation potentials from each compliance option should not be taken for granted, but the utilization rates assumed in the *Steady Progress case* do not assume that any single pathway achieves at the higher end of its potential range. Given that some credit generation options, notably electric vehicles, can be expected to increase non-linearly especially coming up to 2030, the analysis suggests that it could be appropriate to toughen the compliance schedule between 2026 and 2030 to ensure that the LCFS credit price remains effective in driving new investments and pulling new low carbon transportation energy into the market.

Several scenarios are presented as sensitivity cases to illustrate the effects of credit generation from particularly significant pathways at the higher ends of their likely range. Performance at the higher end of plausible ranges for passenger ZEV's, heavy-duty vehicle electrification, cellulosic biofuels, ethanol utilization or CCS could support 2030 carbon intensity reduction targets in the 23-25% range. Near-term policy decisions could help determine the performance of these pathways, as well as the technical and regulatory feasibility of the high-alcohol scenario. California has considerable agency create the regulatory context that will help determine whether these more optimistic credit generation scenarios actually occur.

Three additional scenarios were modeled as sensitivity cases to test the implications for the LCFS program of under-performance of one or more pathways. The scenarios with higher VMT, with indirect emissions assigned to lipids, and with slower development of the electric vehicle market and cellulosic biofuels industries ('*delayed progress*') tested significant under-performance in important credit generation options. Even so, the carbon saving in 2030 was in each case within one and a half percentage points of the *Steady Progress* scenario. In any case, in the event of under-performance in any of these aspects, or in others, there are several possible counteracting factors: under-performance of any pathway would tend to result in higher LCFS credit prices, bringing more supply of other credit generation options on-line through market effects; CARB or other policy-makers could increase supply of other credits through complementary policies; and additional credits could come from pathways not modeled in this research (see "Credit Generation Opportunities Not Modeled").

The draft compliance schedule that has been proposed for the period from 2019 to 2030 starts with a slight reduction of targets for 2019 and 2020 compared to the current levels. The modeling undertaken for this report suggests that the ARB has made a reasonable decision in suggesting a slight relaxation of the rate of growth of targets, allowing compliance to be achieved over the coming years without expecting the existing credit bank to be fully exhausted.

At the other end of the regulatory period, the target of 20% proposed for 2030 is already slightly higher than the target outlined in the initial draft illustrative compliance scenario assessment; this higher level of aspiration is supported by the outcomes of the modeling presented herein. While the modest increase in aspiration for 2030 is welcome, the modeling also suggests that the fully linear increases in the compliance schedule from 2023 to 2030 may not adequately reflect the non-linearity that can be expected in growth of supply of some categories of compliance credits, especially towards the end of the coming decade. In particular, as electric vehicles become a larger part of the vehicle pool, electricity consumption for transportation will increase rapidly. Coupled with reducing carbon intensity in the grid electricity mix, this growth will generate very significant numbers of LCFS credits. Perhaps harder to predict is the rate of development of CCS technology. Even the *Clean Refineries* case presented here includes only a modest roll out of CCS technology for relatively easy to capture CO_2 streams at ethanol and petroleum refineries. A breakthrough on CCS costs could make very large emissions reductions achievable at prices well below recent LCFS credit prices; emissions reductions that would inevitably accelerate during the 2020s as the technology is demonstrated.

In all of the scenarios presented here, compliance against the proposed targets becomes easier (or over-compliance increases) as the program approaches 2030. Without adjustment to the compliance schedule, this would drive significant credit banking; but it may also result in such a reduction of LCFS credit prices that supply would drop off, undermining the very businesses that will have facilitated success in the program. It would therefore be appropriate for the ARB to consider setting a more stringent trajectory in the years from 2025 to 2030, to ensure that the LCFS continues to represent a strong driver for progress in the context of increasing credit supply.

Part of the elegance of the LCFS is that it allows a range of decarbonization options to be supported alongside each other on their carbon intensity reduction merits. It would be pointless to pretend that it is possible to accurately predict the full array of low carbon fuels that will be available to California in 2030, and therefore the scenarios presented in this report are just that – scenarios rather than predictions. The decision as to the appropriate level for future LCFS targets is necessarily not a purely technical one, but also a political one. It is our hope that the scenarios presented here may inform the ARB's decision making in this regard, and help demonstrate that targets moderately more ambitious than the 20% for 2030 suggested in the Preliminary Draft Proposed Regulation Order would be reasonable.

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Annex A Updates to modeling framework

A.1 Scaling to California

Malins et al. (2015) is based on results from the VISION 2014 model for the whole of the United States. In order to provide results relevant to the Pacific region, the VISION 2014 outputs were scaled down by the fraction of VMT driven there. In this study, the gasoline and diesel markets have been scaled separately, based on reported consumption of gasoline type and diesel type fuels in California (California Air Resources Board, 2018a).

A.2 Compliance curves

For visualization of results, the compound regional compliance curves developed for Malins et al. (2015) have been replaced by the illustrative compliance curve to 2030 from California Air Resources Board (2018b). The number of banked credits in 2016 is set to 10 million, also based on California Air Resources Board (2017c).

A.3 VMT

The ARB draft illustrative compliance scenarios show significantly lower 2030 total fuel demand than was output by the VISION 2014 model based on default VMT assumptions. As explained in the body of the report, a 6.9% reduction in passenger vehicle VMT has been assumed in the baseline, making the model slightly more conservative on overall reductions in California transportation energy consumption than California Air Resources Board (2017c).

A.4 VISION 2017

The data in the VISION worksheets *Population-GDP data*, *Util Mix, Auto-LT data* and *LV VMT data* have been updated to VISION 2017.

A.5 Additional compliance options

A range of refinery related additional credit generation options that have been added to LCFS since the publication of Malins et al. (2015) have been added to the model. Credits for refinery investment and green hydrogen use are as detailed in the body of the report. Credit generation by innovative crude production and by low energy use refineries are based on the Project/LD/High ZEV/20% scenario in California Air Resources Board(2018a).

A.6 Natural gas vehicles

The VISION 2014 data for natural gas consumption in transportation results in an underestimation of natural gas consumption in the California market. The NG vehicle sales shares for 2010 and 2020 have been calibrated to deliver NG consumption results matching reported California data for 2010 and California Air Resources Board (2017c) for 2020.

A.7 First generation biofuel blends

The initial blends of ethanol and biodiesel have been calibrated to reported fuel volumes. For 2016, the biodiesel blend is 4.25% and the ethanol blend 10.26%. Given progress in resolving NOx emissions issues associated with higher biodiesel blends, the average biodiesel blend in the model is allowed to reach 7.4% by 2020 and 15% by 2030.

A.8 HVO supply

The initial supply of HVO to California has been updated to match reported volumes (California Air Resources Board, 2017c).

A.9 Cellulosic biofuel supply

The list of anticipated facilities from Malins et al. (2015) has been replaced in recognition of delays and cancellations in the intervening period. Cellulosic ethanol projects are based on data reported by Ethanol Producer Magazine[24], while data about pyrolysis and FT plants has been updated on a project by project basis.

A.10 Carbon intensity of biofuels

In general, the carbon intensities used in Malins et al. (2015) are considered to remain reasonable and have been reused.

For the case of renewable natural gas, the average carbon intensity has been adjusted to reflect the potential for increased supply of dairy gas with a large associated emissions credit. Dairy gas supply and landfill gas carbon intensity assumptions are taken from California Air Resources Board (2017c).

For the case of sugarcane ethanol, Malins et al. (2015) assumed used an approved pathway including an electricity cogeneration credit to set the starting carbon intensity. The ARB illustrative compliance scenarios assume a starting sugarcane ethanol carbon intensity that excludes that credit, and therefore a higher starting carbon intensity of 45 gCO_2e/MJ has been adopted for this report. As in the previous study, this carbon intensity is modeled as falling to 24 gCO_2e/MJ over time.

A.11 Carbon intensity of fossil fuels

The carbon intensity of fossil fuels has been updated to reflect values in California Air Resources Board (2018b).

A.12 Passenger electric drive vehicles

It is assumed that 20% of the EV fleet is in category 'A' (range around 100 miles) and 80% in category B (range around 200 miles), and that 20% of the PHEV fleet is in category A (able to run 10 miles on battery) and 80% in category B (able to run 40 miles on battery).

[24] http://www.ethanolproducer.com/plants/listplants/US/Operational/Cellulosic

A.13 Medium and heavy duty electric drive vehicles

The VISION 2014 model does not include representation of medium and heavy duty electric vehicles. An increasing fleet of these vehicles has been modeled outside the VISIO framework by assuming that MD/HD electric vehicles displace an amount of diesel consumption proportionate to the number of vehicles in the medium and heavy duty categories respectively, as detailed in the body of the report. In order to be conservative, it has been assumed that each MD/HD vehicle displaces only 90% of the energy used for a conventional drive vehicle.

Annex B California Clean Medium/ Heavy-Duty Vehicle Stock in 2030: Feasible Optimistic Scenario

This additional analysis was performed by and is included by kind permission of Ryan Schuchard of CALSTART.

	Current (est.)		Feasible Optimistic Scenario by 2030			
	NGV[a]	ZEV[b]	NGV	ZEV	Hybrid[c]	Notes[d]
All MD (Class 2B-6)	1,000	300	75,000	36,700	nil	Figures taken from CARB's Scoping Plan ("Vision Cleaner Technologies and Fuels scenario" in Appendix D – p. 16). Note that ZEV adoption highest in class 2B and last mile delivery trucks. Figures could arguably be higher if they incorporated ZE truck rule (15% of 2B-8 purchases ZE by 2030) or Jan 2018 Executive Order E-48-18, which sets target to deploy 5M ZEVs by 2030.[e]
HD Transit	4,000	150+	2,000	8,000	500	ZEV number based on proposed Innovative Clean Transit Rule (ICTR; ZE purchase requirement phasing from 25% for large fleets in 2020 to 100% for all fleets in 2029). Total pop is around 11,000. Assume most of remainder is NG, based on NGV Roadmap, p. 10 (5000 by 2030), developed prior to ICTR.
HD Refuse	2,000	Pilots	6,400	500	nil	Total pop is 11,000. HD refuse NG from NGV Roadmap, p. 10 (6400 by 2030). HD refuse EV is a rough estimate. Assumes some takeoff but limited size (5% of market)
HD Hostler	nil	Demos	nil	2,500	nil	Total pop is ~5,000. HD hostler EV extrapolated from CALSTART CTM (1000 by 2025)
HD Drayage	2,000	Demos	5,000	7,000	500	Total pop is ~20,000. HD drayage NG from NGV Roadmap, p. 10 (4077 at POLB by 2030). See also CALHEAT. HD EV figures from CTM (5000 by 2025)
HD Delivery	100	Demos	3,000	75000	nil	Total pop is ~75,000. NG 2030 figures from NGV Roadmap, p. 10. 2030 EV figures extrapolated from CALSTART CTM (1500 by 2025) and assume 1,000 in annual sales starting by early 2020s.

HD Regional Haul	~4000	Demos	3,000	7,500	nil	NG 2030 figures from NGV Roadmap, p. 10. HD 2030 figures assume 1,000 in annual sales starting by early 2020s.
HD Line Haul	~4,000	nil	41,000	2,000	500	Total pop is 175,000. NG 2030 figures from NGV Roadmap, p. 10. ZEV growth potential has big unknowns. 50 ZEVs in 2019 with 20% CAGR would equate to ~2400 cumulative sales by 2030, or 2,000 purchased after 2023 which would all contribute to 2030 vehicle stock, assuming 7-year vehicle life.

a) Natural Gas Vehicles. Assume 90%+ of fuel use is RNG.
b) Zero-Emission Vehicles including battery electric and fuel cell vehicles.
c) Hybrid includes electric hybrid vehicles, plug-in hybrid electric vehicles (PHEV) that allow for some zero-emission range, and extended range (XR) vehicles that have series electric drive with power generator to allow longer range driving.
d) CARB scenarios taken from CARB Scoping Plan, Appendix D. Note that CARB assumes 4.2M electric LDVs in addition to MHDVs here.
e) For reference, the minimum number of ZE class 2B-7 trucks required by ZE truck rule (15% of purchases ZE by 2030) corresponds to around 27,000 ZE trucks, based on 1.3M vehicles in class 2B-3 fleet and 386,300 in class 4-7 fleet, assuming 11 year vehicle life. Truck rule presentation: https://www.arb.ca.gov/msprog/actruck/mtg/170830arbpresentation.pdf. Also, the shuttle rule requires 100% of purchases ZE by 2030. Shuttle rule presentation: https://www.arb.ca.gov/msprog/asb/workgroup/dec4presentation.pdf.

B.1 Discussion

The 2030 figures are intended to illustrate on-road vehicle stock that can reasonably be expected in California by 2030 assuming implementation of major clean vehicle regulations that are currently being proposed, including the Innovative Clean Transit Rule (ZE purchase requirement phasing from 25% for large fleets in 2020 to 100% for all fleets in 2029) ZE shuttle rule (ZE purchase requirement of 100% of by 2030) and clean truck rule (ZE manufacturer requirement of 15% of class 2B-8).

The above is not a projection, but rather, a scenario for an optimistic but plausible number of clean vehicle deployments. Critical variables that will affect actual vehicle deployments include (1) Battery costs, weight, charging speeds, and lifespan, (2) Adoption of autonomous and TNC driving tech, (3) Fuel prices, (4), Availability of R&D and incentive funding, (5) Availability of fueling and charging infrastructure, and (6) Supporting laws and regulations.

For simplicity, we assume that between now and 2030, the total number of vehicle stock and fuel use will remain relatively constant (for the latter condition, an increase in both VMT and fuel economy cancel each other out).

Although NGVs and ZEVs are broken into separate categories, we can assume for a high-deployment scenario that 80-100% of NGVs use renewable fuel, and hence for the purposes of modeling, the two categories have similar CI profiles.

Additional ZEV deployments that could be expected include forklifts (193,000 by 2030 for in-between case), airport GSE (5,000), truck stop electrification (2,000), and TRUs (67,000).[25]

B.2 Additional References:

CALSTART (2015) CALHEAT

CALSTART (2014) NGV Roadmap

ICF TEA Study (2014)

CARB (2017). Proposed Fiscal Year 2017-18 Funding Plan for Clean Transportation Incentives

[25] ICF, 2014.

Annex C Detailed credit generation in *Steady Progress* and *High Performance* scenarios

Table 14 Credits generated (million tonnes) by low carbon fuel pathways considered in the *Steady Progress* scenario

Fuel	2020	2025	2030
Starch Ethanol	2.6	2.0	1.5
Sugar Ethanol	1.0	1.1	0.9
Cellulosic Ethanol	0.1	0.4	0.6
Renewable Gasoline	0.0	0.0	0.1
Hydrogen for LDVs	0.1	0.6	1.4
Electricity for LDVs	1.8	5.8	13.1
CARBOB Deficits	-14.8	-21.8	-25.9
Biodiesel	2.3	4.1	3.7
Renewable Diesel	5.8	7.8	5.7
Renewable NG	1.4	2.4	4.2
Electricity for HDV	0.0	0.3	1.6
Electricity for Rail/Forklift/etc.	0.4	0.3	0.3
Diesel Deficits	-2.9	-4.3	-6.6
Cellulosic diesel	0.0	0.1	0.2
Refinery CCS and Investment Credits	0.1	0.3	0.8
Refinery Renewable Hydrogen	0.2	0.5	0.8
Innovative Crude Credits	0.3	0.9	1.0
LC/LEU Refinery	0.2	0.2	0.2
Ethanol CCS	0.0	0.0	0.6

Table 15 Credits generated (million tonnes) by low carbon fuel pathways considered in the *High Performance* scenario

Fuel	2020	2025	2030
Starch Ethanol	2.6	1.8	0.9
Sugar Ethanol	1.0	1.0	0.6
Cellulosic Ethanol	0.3	1.1	2.7
Renewable Gasoline	0.0	0.0	0.4
Hydrogen for LDVs	0.1	0.7	1.9
Electricity for LDVs	1.8	6.5	15.5
CARBOB Deficits	-14.9	-21.9	-25.8
Biodiesel	2.1	3.7	3.3
Renewable Diesel	5.8	8.0	6.7
Renewable NG	2.2	3.5	5.4
Electricity for HDV	0.0	0.3	1.6
Electricity for Rail/Forklift/etc.	0.4	0.3	0.3
Diesel Deficits	-2.8	-3.7	-5.3
Cellulosic diesel	0.0	0.3	1.2
Refinery CCS and Investment Credits	0.1	0.4	2.1
Refinery Renewable Hydrogen	1.6	1.6	1.9
Innovative Crude Credits	0.3	0.9	1.0
LC/LEU Refinery	0.2	0.2	0.2
Ethanol CCS	0.0	0.0	0.6

Annex D Further updates to modeling framework for update report

- In Malins (2018), no incremental crude deficits were modeled (following CARB, 2017c). Incremental crude deficits have now been added based on the projection in the illustrative compliance scenarios (CARB, 2018a).
- Malins (2018) used the corn ethanol carbon intensity projections from Malins et al. (2015). This included an assumed reduction of average corn ethanol carbon intensity to the level of the lowest approved 2012 corn ethanol pathway by 2030 (60 gCO_2e/MJ). This was based on a biogas fueled corn ethanol plant. Recognizing uncertainty about availability of biogas for corn ethanol process fuel in 2030, the 2030 CI value has been adjusted to instead reflect the lowest non-biogas pathway documented in the CARB current pathways list (https://www.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm, page last updated 10 April 2018). The average CI of corn ethanol is therefore assumed to fall to 65 gCO2e/MJ by 2030 (the current pathway value for Pacific Ethanol at Stockton). CI reductions due to CCS implementation are additional to this. In the earlier modeling, sorghum ethanol was assumed to have a lower average CI than corn ethanol, based on the 2012 pathways. In the latest published pathway overview, there is not a significant difference between average corn and sorghum results, and so all starch ethanol is assumed to achieve the same CI.
- The 2017 CI for corn ethanol was set at 74 gCO2e/MJ in Malins (2018), which is higher than the 71 gCO2e/MJ documented by CARB (2018a). The starting corn CI has therefore been revised down to match the CARB data.
- The carbon savings delivered by ethanol CCS were bundled with petroleum refinery CO2 reductions for visualization in the graphs in Malins (2018). For the update report, GHG savings delivered by CCS at ethanol plants have been shifted to be represented as a reduction in CI for conventional starch ethanol. The total emissions reduction and associated credit generation from CCS at ethanol facilities is unchanged.
- In Malins (2018), in the baseline MD/HD electric vehicle rollout scenario, sales were set zero up to 2023. They are now gradually increased from 2020 through to 2023, after which they are the same as before.
- CARB (2018a) assume that a small amount of renewable propane is generated as co-product of HVO renewable distillates production. The model has been updated to match total propane consumption projected in the illustrative compliance scenario, and to include renewable propane as an HVO co-product.

- In Malins (2015), the CI of hydrogen supplied for electric vehicles was assumed to reflect a mix of fossil-derived, biogas-derived and electrolytic hydrogen, with a falling CI to 2030 as the fossil –derived hydrogen fraction reduced. In the illustrative compliance scenarios, CARB set the CI of hydrogen based on steam methane reforming of biogas. This reflects the option to use book and claim biogas accounting to treat all hydrogen as biogas derived. We have now adopted the CARB CI assumption (40 gCO2e/MJ, EER adjusted).
- The calibration to the California market size has been improved as the modeling for Malins (2018) was estimating more 2016 transport energy demand than documented by CARB, resulting in slightly lower transport energy demand in the model throughout the model period.
- In Malins (2018), generation of refinery and ethanol CCS credits was assumed to grow exponentially. Following feedback received on the earlier report, and recognizing the incentive for refineries to act earlier in the program period to maximize credit generation, this has been adjusted to a linear growth trajectory reaching its maximum deployment in 2028.
- Options for time-of-use dependent CI reporting for electricity consumption and for reporting of zero carbon electricity use through green tariffs have been added, as documented in the body of the report above.

Memo

To: Chris Malins, Cerulogy
From: Colin Murphy, NextGen Policy Center
Jeremy Martin, Union of Concerned Scientists
Date: March 9, 2018, with Author's update March 23, 2018
Re: Basis for Carbon Capture and Sequestration Estimates

The following explains the basis for the CCS estimates available by 2030 as part of fuel pathways under the California Low Carbon Fuel Standard.

Low-CCS Estimate:

We screen for potential opportunities for high-efficiency CCS implementation under the LCFS where streams of high-concentration and/or high-pressure CO2 can be found in fuel production. After consulting with several experts, this focused on fermentation tank blow-off from ethanol production and process - but not heating- emissions from steam methane reformation (SMR) units, which produce hydrogen for refineries and chemical industries.

There are some technical challenges involved in CCS from the SMR units, related to adding a complex process in mid-stream at existing units, so as a conservative baseline assumption, these are excluded from the low-CCS estimate, leaving fermentation blow-off as the primary source of CCS credits. While any ethanol facility that ships to California could feasibly generate these credits, the Low-CCS estimate will assume only CA ethanol production facilities will do so, in part because there could be potential benefits under CA's cap-and-trade rule or other climate policies (though no provisions yet exist) and in part to reflect conservative assumptions.

Mid-CCS Estimate:

Under the mid-CCS estimate, we assume CCS of fermentation emissions occurs at all ethanol facilities shipping to California, based on economic analysis from recent research.

In addition to ethanol facilities, this scenario assumes the technical challenges for CCS from SMR can be overcome, leading to development in this space. We limit application to SMR facilities in the Bay Area, due to proximity to a potential geological disposal site (depleted natural gas wells in the Delta) and because they are clustered in a limited geographic area, which would allow for shared pipeline and compression infrastructure.

For the mid-CCS case, we consider SMR units at Bay Area refineries, and assume all hydrogen production for these SMR units is for transportation fuel at refineries. This likely yields a slight overestimate of total transportation-related hydrogen production, which is balanced by a conservative assumption on CO2 recovery rate. CO2 would be transported by pipeline for geological storage in decommissioned natural gas wells in the Delta. Assume no additional natural gas recovery from storage wells as a result of CO2 sequestration.

For High-CCS Estimate

The High-CCS estimate assumes that post-combustion capture becomes cost-effective at prices supported by likely LCFS credit levels combined with Federal 45Q tax credit. At this level, CCS could be widely deployed at transportation fuel facilities by 2030, leading to massive LCFS credit generation. California refineries emit over 37 million tonnes of CO2 each year, of which almost 16 million tonnes comes from the Bay Area. Assuming 70% capture of just Bay Area refining yields almost 11 million tonnes of emissions reduction, well over half of predicted 2030 credit obligation for the entire LCFS program. 70% capture at all refineries, including those in Southern California, could exceed the total 2030 LCFS credit generation on its own.

In addition to refineries, cost-effective post-combustion CCS could also dramatically reduce emissions from ethanol, renewable diesel and and other transportation fuel producers, which would further increase the credit generation potential.

As a result, we will not explicitly model the High-CCS scenario and instead note that if post-combustion capture becomes widely deployed at commercial scale in CA, this would radically re-shape the LCFS credit markets and potentially crowd out investments in alternatives to petroleum fuels. If this were to happen, CARB may need to consider significant amendments to the program to ensure consistent market signals and maintain progress towards a transportation system compatible with long-term GHG-reduction goals.

In-State CCS from Ethanol Production (Present in Low and Mid-CCS scenarios):

Capture of fermentation emissions reduces ethanol CI by 32 g/MJ, per this presentation from Sean McCoy of LLNL (determined by subtracting “Fermentation CCS” CI from “Baseline” CI on slide 9 from his presentation.[1] A co-author confirmed this is an appropriate interpretation of their results). This value appears to consider life cycle emissions from the CCS system.

California produces 217.5 Million gallons of ethanol in-state at present.[2] We conservatively assume no additional ethanol production capacity to 2030.

Ethanol’s energy intensity is 81.51 MJ/gal (Physical constant, multiple sources)

[1] https://www.cslforum.org/cslf/sites/default/files/documents/tokyo2016/McCoy-BiofuelsCCS-TG-Tokyo1016.pdf.
[2] http://www.neo.ne.gov/statshtml/121.htm

This yields:

217,500,000 (gal/year) * 81.51 (MJ/gal) * 32 (grams/MJ) * 1/1000000 (tonnes/gram) ≅ **567,000 tonnes/year**

Out-of-State Ethanol CCS from Ethanol Production (Present in Mid-CCS Scenario)

Depending on scenario and modeling assumptions, CA conventional ethanol consumption in 2030 varies between 1 and 1.5 billion gallons per year (LCFS Draft Compliance Scenario Calculator). A high-ethanol scenario, such as broad deployment of E15, or other high-ethanol blends could get up to 2 billion gallons of ethanol. Using the 7.5 lb/gallon figure from above, this results in a maximum possible fermentation CO2 emission rate of 6.8 million tonnes/year from fermentation emissions associated with production of ethanol for use in California.

Sanchez, Johnson, McCoy and Turner,[3] indicate that 34 million tonnes/year of CO2 from Midwest ethanol plants could be sequestered at a cost < $60/tonne. This is significantly lower than the combined value of LCFS credits and Section 45Q credits. [See footnote for update]

Since the potential for CO2 sequestration of ethanol fermentation emissions greatly exceeds the emissions associated with California's consumption at prices well below that which would be available to producers under likely 2020-2030 conditions, the Mid-CCS scenario assumes that all ethanol fermentation emissions would be sequestered.

Repeating the methodology from the In-State calculation, based on an estimated 1.2 billion gallons total ethanol produced, of which 765 are corn, in the *Steady Progress* scenario yields. We assume only corn ethanol is paired with CCS:

765,000,000 (gal/year) * 81.51 (MJ/gal) * 32 (grams/MJ) * 1/1000000 (tonnes/gram) ≅ **2 million tonnes/year (1.995 million without rounding)**

CCS on SMR units in Northern CA (Present in Mid-CCS Scenario)

Soltani, et al.,[4] indicates that the most efficient phase of the process at which to implement CCS is after the syngas shift but before pressure-swing separation, due to the high pressure of the gas stream at this point. The process can be optimized for CCS potential, at which 65% of total process CO2 emissions could be recovered (assuming 90% of CO2 capture efficiency) or

[3] http://dc.engconfintl.org/cgi/viewcontent.cgi?article=1041&context=co2_summit3.

Author's update: A more comprehensive explanation of this work was accepted for publication after this memo was first published: D.L. Sanchez, N. Johnson, S. McCoy, P.A. Turner, K.J. Mach. "Near-term deployment of carbon capture and storage from biorefineries in the United States" Proceedings of the National Academies of Sciences (In Press).

[4] https://www.sciencedirect.com/science/article/pii/S0360319914027566

optimized for maximum hydrogen production rate, at which 36% of CO2 emissions could be recovered. (Estimated by dividing the process emissions line by total emissions line for all S/C ratios in Table 2).

H2A modeling from the DOE[5] claims 81% of total CO2 could be captured by CCS (determined by dividing the mass flow of CO2 from the CO2 stream by the sum of CO2 mass flows from the CO2 stream and flue gas stream).

In evaluating BAAQMD monitoring reports for SMR units, it appears that many are run below their rated capacity, presumably to match demand. Given the excess theoretical capacity, it is reasonable to assume that the potential value of CCS in excess of $150/ton from LCFS credits and Federal 45Q tax credits would be a sufficient incentive to run the SMR under conditions nearer to those optimal for CO2 recovery than for hydrogen production. Accordingly, we assume a net CO2 sequestration rate near the upper end of the range from the Soltani paper, but well below the theoretical limit proposed by DOE: 60%.

Relevant SMR Units and Emissions:

Using the EPA facility-level GHG emission inventory,[6] we select Subpart P emissions from Northern CA refineries and SMR facilites known to sell primarily to refineries.

Facility	**CO2 Emissions (tonnes/yr)**
Shell Martinez Refinery	816174
Valero Benicia Refinery	948212
Tesoro Golden Eagle Refinery	562646
Chevron Richmond Refinery	1334862
Air Products & Chemicals Martinez (Shell)	723983
Air Products & Chemicals Martinez (Tesoro)	264024
Air Liquide Rodeo (Shell)	769835
Shell Rodeo	111304
SUM	5,531,040

[5] DOE H2A Project "Current Central Hydrogen Production from Natural Gas with CCS" https://www.hydrogen.energy.gov/h2a_prod_studies.html

[6] https://ghgdata.epa.gov/ghgp/main.do

Based on the 60% sequestration assumption, this yields **3.3 million metric tonnes** per year of sequestration.

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LCFS Refinery Investment Credit Analysis

Prepared for
NextGen Climate America, Inc.

By
Stillwater Associates LLC
Irvine, California, USA

March 9, 2018

Stillwater Associates

3 Rainstar Irvine, CA 92614 – Tel (888) 643 0197 – www.stillwaterassociates.com

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Executive Summary

The Low Carbon Fuel Standard (LCFS) is a California greenhouse gas (GHG) regulatory program which aims to reduce the carbon intensity (CI) of energy used in California transportation. The regulation covers petroleum fuels, renewable fuels, and alternative transportation technologies. The design of the program is such that renewable fuels and alternative transportation technologies generate LCFS credits, and petroleum gasoline and diesel generate LCFS deficits. Parties with LCFS deficits must either generate or purchase LCFS credits to comply with the LCFS. California's Air Resources Board (CARB) is responsible for administering the LCFS regulation.

In its 2015 re-adoption of the LCFS, CARB introduced two pilot programs offering petroleum refineries opportunities to generate LCFS credits: The Refinery Investment Credit Pilot Program (RIC) and the Renewable Hydrogen Refinery Credit (RHRC) Pilot Program. Since then, CARB has hosted workshops on the RIC and RHRC programs. Then, on February 20, 2018 CARB released unofficial LCFS rulemaking documents and 2018 Draft Amendments to the LCFS Regulation. NextGen Climate America engaged Stillwater Associates to conduct an analysis of the potential range of future LCFS credit generation from the RIC and RHRC provisions that could impact the 2030 targets for the LCFS.

We analyzed the six types of RIC and RHRC projects provided for within the scope of CARB's draft proposed regulation:

1. Carbon Capture and Sequestration (CCS)
2. Use of Renewable or Low-CI Electricity
3. Use of Low-CI Process Energy
4. Electrification at Refineries
5. Process Improvements
6. Renewable Hydrogen

Taking into account as many factors as possible (with sometimes limited data), we determined the unconstrained credit possibilities in each project category, then applied the likely legislative, logistic, and economic constraints to produce a low, mid, and high credit generation case for 2030 in each project category. Finally, we totaled the six categories to arrive at low, mid, and high credit cases for all RIC and RHRC projects in 2030:

Possible LCFS Credits – MT CO_2e/year			
	High	**Mid**	**Low**
CCS	2,000,000	730,000	365,000
All Other RIC & RHRC	2,670,000	1,136,000	310,000
TOTAL	**4,670,000**	**1,866,000**	**675,000**

Our analysis concludes that the two most likely sources for LCFS Credits under RIC and RHRC in 2030 will be Carbon Capture and Sequestration projects and Renewable Hydrogen projects.

This study was commissioned to develop the order of magnitude range of RIC and RHRC credits considering the current and proposed regulatory framework, the equipment used in California's refineries, and Stillwater's judgement as to the economics and feasibility of possible projects. Due to the short deadline for this study, limited in-depth data about the refineries, and undefined costs of refinery modifications, we performed only limited detailed analysis to refine the range of potential credits. Thus, in most cases, the range presented is based on judgement as much as analysis.

1 Introduction

1.1 LCFS Background

California's Low Carbon Fuel Standard (LCFS) is part of a suite of legislative efforts in California to combat climate change. The LCFS was initiated in 2007 by executive order S-1-07 from California's governor, Arnold Schwarzenegger. The program was then incorporated as a California regulation in 2009 as one of the Assembly Bill 32 (AB32) programs to reduce greenhouse gas (GHG) emissions. AB32, also known as the Global Warming Solutions Act of 2006, requires the California Air Resources Board (CARB) to develop regulations and market mechanisms to reduce GHG emissions to 1990 levels by 2020. There is a broad array of regulations under the umbrella authority provided by AB32. For the sake of this paper, we will focus our discussion on the Refinery Investment Credit Pilot Program (RIC) and the Renewable Hydrogen Refinery Credit Pilot Program (RHRC) provisions of the LCFS.

1.2 2015 Re-Adoption of the LCFS

1.2.1 Refinery Investment Credit Pilot Program

In its 2015 LCFS re-adoption,[1] CARB introduced the RIC under which refineries can earn LCFS credits for reducing total GHG emissions from their facilities. Credits granted are based on "fuel volumes sold, supplied, or offered for sale in California." CARB's goal with this program was to encourage reductions in GHG emissions through major process improvements, fuel switching, and carbon capture and sequestration. Under the initial regulation, RIC projects were required to achieve a carbon intensity (CI) reduction from the comparison baseline of at least 0.1 grams carbon dioxide equivalent per mega joule (gCO_2e/MJ). RIC projects must mitigate any net increases in criteria air pollutant or toxic air contaminant emissions from the refinery in accordance with all environmental and health and safety regulations. Refinery equipment shutdowns, reductions in refinery or equipment throughput, and refinery maintenance are not eligible for RIC. Furthermore, under the original RIC program, a regulated party who generates credits under the program could use the credits to cover its deficits (refiner's obligations) but could not sell or transfer the credits to another party nor use those credits to meet more than 20 percent of its annual obligation.

According to CARB, as of late 2017 there were no projects approved under the RIC provisions despite discussions and interest from refiners to use this provision. Many factors contribute to the difficulty of making progress on any RIC projects, including the complexity of refinery operations; CARB's requirement for all possible impacts to be evaluated; GHG measurement, baseline, and reduction verification requirements; the 0.1 gCO2e/MJ reduction threshold; and the lack of specific protocols to calculate project credits.

1.2.2 Renewable Hydrogen Refinery Credit Pilot Program

In addition to the RIC program, CARB also introduced its RHRC Pilot Program in the 2015 re-adoption of the LCFS. Under the RHRC, refineries may earn LCFS credits for GHG emission reductions from the "production of CARBOB or diesel fuel that is partially derived from renewable hydrogen." Like the RIC program, RHRC program credits are based on "fuel volumes sold, supplied, or offered for sale in California." Under current rules, to qualify as an RHRC project, a refinery must replace a minimum of one percent of all fossil hydrogen in the production of CARBOB or diesel fuel with renewable hydrogen each year. Similar to the RIC program, refineries must mitigate any net air contaminants or pollutants and cannot sell or transfer RHRC credits to any other party. A regulated party who generates credits under the RHRC program may use the credits to cover its deficits (refiner's obligations) but may not sell or transfer the credits to another party nor use those credits to meet more than 10 percent of its annual obligation.

[1] California Air Resources Board. Low Carbon Fuel Standard Final Regulation Order. November 16, 2015 https://www.arb.ca.gov/regact/2015/lcfs2015/lcfsfinalregorder.pdf

1.3 Latest RIC Developments

The February 20, 2018 draft proposed regulation[2] creates a more specific outline for the RIC, providing for five project areas: carbon capture and sequestration (CCS), use of renewable or low-CI electricity, use of low-CI process energy, electrification at refineries, and process improvements. CARB has also proposed changing the 0.1 gCO2e/MJ CI reduction threshold to a 1% GHG emissions reduction from pre-project, on-site, refinery-wide GHG emissions in metric tons per year. The draft proposed regulation would allow for credits generated under the RIC provision to be sold or transferred to another party.

1.4 Latest RHRC Developments

In its February 20, 2018 draft proposed regulation, CARB leaves much of the original RHRC program in place with just a few tweaks. The proposal removes the provision requiring that renewable hydrogen replace at least 1% of the fossil hydrogen in the production of CARBOB or diesel fuel. The draft proposed regulation would also allow for credits generated under the RHRC provision to be sold or transferred to another party.

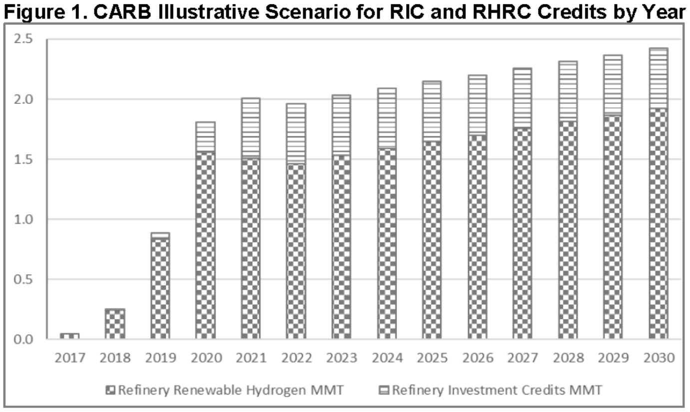
1.5 Program regulatory outlook through 2030

CARB's *Unofficial LCFS Rulemaking Documents*,[3] offered a look at where the LCFS program is headed. The primary significance of this document release is that it contained two considerable changes to the LCFS reduction schedule. First, instead of the initially mandated 10% CI reduction from the 2010 baseline in 2020, the 2020 reduction is proposed to be 7.5% with the 10% reduction delayed two years to 2022. Second, instead of the 18% LCFS reduction in 2030 from the 2010 baseline in prior CARB documents, the proposed reduction target is increased to 20% in 2030. If this release of documents is anything, it is a significant shift in the original CI reduction target, which was set back in 2010, and it represents a recognition that the fuels mix has not changed rapidly enough to insure there is a positive credit bank in 2020. In the longer term, CARB has signaled a more ambitious goal of a 20% reduction rather than the 18% reduction indicated in prior documents.

1.6 CARB RIC and RHRC Illustrative Scenarios

CARB has published a "Draft Illustrative Scenario Compliance Calculator"[4] that contains assumptions for the growth of credits generated from all sources. To establish a benchmark, CARB's assumed credit generation from RIC and RHRC is shown in Figure 1 below.

Figure 1. CARB Illustrative Scenario for RIC and RHRC Credits by Year



[2] California Air Resources Board. Proposed Regulation Order: Appendix A. February 20, 2018. https://www.arb.ca.gov/regact/2018/lcfs18/appa.pdf
[3] California Air Resources Board. LCFS Rulemaking Documents. February 20, 2018. https://www.arb.ca.gov/fuels/lcfs/rulemakingdocs.htm
[4] California Air Resources Board. Draft Illustrative Compliance Scenario Calculator. August 7, 2017. https://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/draft_illustrative_compliance_scenario_calculator.xlsx

As Figure 1 shows, CARB projects a significant amount of credits - almost 2 million metric tonnes (MT) per year by 2030 - from the RHRC provision, and projected RIC generation of about 0.5 million MT per year. The total of RIC and RHRC provisions is 2.4 million MT in 2030.

2 Study Methodology

This study was commissioned to develop the order of magnitude range of RIC and RHRC credits that might be expected in 2030 considering the current and proposed regulatory framework, the equipment used in California's refineries, and Stillwater's judgement as to the economics and feasibility of possible projects. Due to the short deadline for this study, limited in-depth data about the refineries, and undefined costs of refinery modifications, we performed only limited detailed analysis to refine the range of potential credits. Thus, in most cases, the range presented is based on judgement as much as analysis.

Generally, for each credit-generating project category, we determined an unconstrained level of credits – the level of potential credits, given no regulatory, input, resource, or economic constraints. (For example, we include the physically impossible scenario in which all electricity used in California refineries is replaced by solar power.) We then derived an estimated range of viable credits for 2030 from the unconstrained potential credits by applying regulatory constraints, likely input and resource constraints, and Stillwater's judgement as to economic viability of projects in each credit-generating category. Our conclusions would be altered significantly by changes to the regulatory, input, resource, or economic inputs.

Stillwater drew upon quarterly data from the LCFS Reporting Tool (LRT),[5] CARB's Illustrative Scenario calculator,[6] various U.S. Energy Information Administration (EIA)[7] data series, the LCFS regulation,[8] the EIA's Annual Energy Outlook,[9] and EIA[10] and Oil & Gas Journal reports of refinery capacity.[11] We employed our knowledge of California's refineries and refinery operations, as well as our experience in refinery investment decision making, to establish a sense of the viability of projects which would generate LCFS credits. An LCFS credit price of $125/MT is used to establish the LCFS-based project incentive. For lower investment projects – those for which most of the economic benefit comes from the LCFS – the economics of these projects could be highly sensitive to LCFS prices. The incentives offered by other programs (Cap and Trade, NOx RECLAIM, the Federal Renewable Fuel Standard, renewable power, etc.) are considered as a second order factor.

A benchmark for the refinery reductions of CO_2-equivalent (CO_2e) emissions for the RIC program is the total amount of emissions recorded by CARB for California refiners from the Cap and Trade program – about 35 million metric tons per year.[12] The scope of emissions from RHRC is outside the scope of facility emissions in Cap and Trade.

[5] California Air Resources Board. LCFS Quarterly Data Spreadsheet. January 31, 2018. https://www.arb.ca.gov/fuels/lcfs/dashboard/quarterlysummary/quarterlysummary_013118.xlsx
[6] California Air Resources Board. Draft Illustrative Compliance Scenario Calculator. August 7, 2017. https://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/draft_illustrative_compliance_scenario_calculator.xlsx
[7] U.S. Energy Information Administration. Petroleum & Other Liquids. Accessed May 8, 2018. https://www.eia.gov/petroleum/data.php
[8] California Air Resources Board. Low Carbon Fuel Standard Final Regulation Order. November 16, 2015 https://www.arb.ca.gov/regact/2015/lcfs2015/lcfsfinalregorder.pdf
[9] U.S. Energy Information Administration. Annual Energy Outlook 2017. January 5, 2017. https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf
[10] U.S. Energy Information Adminstration. Refinery capacity data by individual refinery as of January 1, 2017. https://www.eia.gov/petroleum/refinerycapacity/refcap17.xls
[11] Oil & Gas Journal. Refining Capacities. December 4, 2017. https://www.ogj.com/oil-processing/refining/capacities.html
[12] California Air Resources Board. 2016 GHG Emissions Data. November 6, 2017. https://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/2016-ghg-emissions-2017-11-06.xlsx

3 RIC and RHRC Project Categories

The current LCFS regulatory text,[13] adopted in 2015, provides for RIC projects under three categories: process improvements, fuel switching, and CCS. The draft regulatory text[14] released on February 20, 2018 expands that to five project areas for the RIC: CCS, use of renewable or low-CI electricity, use of low-CI process energy, electrification at refineries, and process improvements. In addition to the five RIC areas, renewable hydrogen[15] (as outlined in the RHRC) would also benefit refineries by generating LCFS credits. In this section, we will discuss the potential for projects in each of the five areas outlined under the proposed RIC in addition to RHRC.

3.1 Carbon Capture and Sequestration

Under the draft proposed regulation, CCS projects are defined as: "CO_2 capture at refineries, or hydrogen production facilities that supply hydrogen to refineries, and subsequent geologic sequestration." More explicit and detailed protocols and provisions for CCS are included in the draft proposed regulation than had been outlined in prior CARB documents. Our analysis of potential CCS credits will focus on projects allowable under the proposed regulatory language.

Almost all the direct CO_2 emissions from a refinery are from one of two sources – fuel combustion or the creation of hydrogen gas. In every refinery, CO_2 is generated through the combustion of fuel, natural gas, or refinery gases used for process heat, steam production, and (in refineries with power generation equipment) generation of electricity. In refineries with hydrogen plants or third-party hydrogen production facilities, another source of CO_2 emissions is the reaction that produces hydrogen from methane and other light hydrocarbons.

Recovering CO_2 from combustion sources is difficult and costly since the concentrations of CO_2 are low and stack gases are hot. Recovery of CO_2 from combustion gases is similar to recovery from power generation steam boiler cycle plants without the economies of scale or the added concentration of CO_2 when coal is the fuel. For the purposes of this study, we concluded that a $125/MT LCFS credit price is too low to incentivize CO_2 recovery from refinery combustion sources.

The most plausible source of CO_2 for capture and sequestration in refineries is from the steam-methane reforming reaction that creates hydrogen gas. This reaction generates a hydrogen-rich gas and a CO2 byproduct: $CH_4 + 4H_2O \rightarrow 4H_2 + CO_2$

To obtain a pure, concentrated hydrogen product, CO_2 is removed from the hydrogen-rich gas. Available removal technologies produce either a highly concentrated (~99%) CO_2 stream or a CO_2 stream that is diluted with unreacted methane, carbon monoxide, and some hydrogen. Older liquid absorption technologies produce the highly concentrated CO_2 streams, while the diluted stream is produced by newer solid-bed adsorption technology where the dilute stream is used as fuel for the process. With this solid-bed adsorption technology, the CO_2 from the reaction does not combust, but instead vents with the stack gases.

A good portion (we estimate 2,500 short tons per day) of the high-concentration CO_2 produced by refineries is used by industrial gas suppliers to produce liquid CO_2 for food (carbonation and packaging), medical, industrial gas, and dry ice uses. (In the U.S., another primary use of CO_2 is to enhance oil field production, but we have seen no evidence that the CO_2 from California's refineries is used in this application.) Although the CO_2 is subsequently used, these emissions are still attributed to the original source – the refinery – since after use they enter the atmosphere.

[13] California Air Resources Board. Low Carbon Fuel Standard Final Regulation Order Section 95489(f). November 16, 2015. https://www.arb.ca.gov/regact/2015/lcfs2015/lcfsfinalregorder.pdf
[14] California Air Resources Board. Proposed Regulation Order: Section 95489(e). February 20, 2018. https://www.arb.ca.gov/regact/2018/lcfs18/appa.pdf
[15] California Air Resources Board. Proposed Regulation Order: Section 95489(f). February 20, 2018. https://www.arb.ca.gov/regact/2018/lcfs18/appa.pdf

Aside from the CCS provision, hydrogen plants may be included in two other credit provisions: reduction of fossil CO_2 emissions from combustion by using biogas, and renewable hydrogen by feeding biogas. We will discuss these credit provisions in sections 3.3 and 3.6, respectively.

3.1.1 Unconstrained Possibility for CCS

There are 12 fuel-producing refineries in California. Two of these refineries are small, leaving ten major fuel-producing refineries. In addition to these refineries, there are five hydrogen production facilities (HPF) that supply hydrogen to refineries. These ten refineries and five HPFs produce a total of approximately 1,100 million cubic feet per day[16] of hydrogen. Assuming that the feedstock is all methane, these operations produce approximately 5.2 million MT of CO_2 per year.

We estimate the CO_2 produced from reaction distributes as:

- 0.9 million MT/year to food, medical, and industrial gases
- 1.7 million MT/year high concentration CO_2 vented to atmosphere
- 2.6 million MT/year dilute CO_2 from solid-bed absorption technology

Each of these categories of CO_2 distribution presents its own challenges for applying CCS technology. In order to participate in sequestration efforts, the first category's already liquefied CO_2 would need to be diverted from other uses or the contracts supplying industrial gas plants would need to be terminated. Capture and sequestration of the CO_2 in the second category would require new investment in CO_2 compression, liquefaction, storage, and logistics to produce a liquid CO_2 that can be transported to a sequestration site. The third category's primary challenge is the additional level of investment required to concentrate the CO_2 from the dilute stream prior to liquefaction.

The significant level of necessary investment notwithstanding, CCS from hydrogen plant byproduct CO_2 could represent a large source of LCFS credits.

3.1.2 High, Mid, and Low Refinery CCS Credit Generation Possibilities

Aside from the requisite investment capital and meeting the CCS protocols, CCS potential is not really supply constrained. We estimate that economically viable investment in recovering CO_2 from hydrogen plant vent gases would require credit prices higher than the $125/MT price we assume for this study because of logistical challenges, economic realities, and uncertainty around sequestration or enhanced oil recovery sites.

Our estimates for the 2030 high, mid, and low cases for CCS are displayed in Table 1. In all cases, we assumed 20% of current CO_2 liquefaction capacity is used for CCS.

Table 1. Possible CCS LCFS Credits (MT per year)

High	Mid	Low
2,000,000	730,000	365,000

3.2 Use of Renewable or Low-CI Electricity

Refineries use a significant amount of electric power in their operations. Depending on the refinery, the power might be grid-supplied, co-generated (generated simultaneously with steam), or a combination of the two. We estimate that each of the ten major California refineries use 50-100 megawatts (MW) of power.[17] The primary use of power in a refinery is for the motors which drive pumps and compressors.

While low-CI electricity technically could be generated by using biogas, we have found no evidence that biogas would be economical since it could be used directly as LNG or CNG to earn LCFS

[16] Stillwater estimate based on California hydrogen generation capacity.
[17] Stillwater estimate.

credits, and that option would be reflected in its price. Similarly, other low-CI pathways to electricity can be better monetized through means other than the RIC.

3.2.1 Unconstrained Possibility for Renewable or Low-CI Electricity

We estimate that roughly 250 MW of power is provided to refineries through co-generation and would not be replaced. So, the ten refineries in California use approximately 500 MW of grid power. Applying a 100 gCO_2/MJ carbon intensity to the grid power yields an unconstrained potential GHG reduction (if all this power were replaced with renewable solar power) of 1.6 million MT per year. The unconstrained potential for renewable or low-CI electricity is high, but for regulatory reasons, the true potential is much lower.

The 2015 re-adopted LCFS and draft proposed LCFS regulations greatly restrict the sources of renewable and low-CI electricity. These sources must be within the boundaries of the refinery or be supplied "behind the meter" while connected via a dedicated line within the utility meter for both generation and receiving facilities. Restricting renewable or low-CI electricity projects to the refinery property or adjacent properties severely limits the potential of this provision. All of California's refineries are located in urban, developed, ecologically sensitive, or high-land-value areas where developing solar projects of the scale meaningful to a refinery's power use would be exceedingly expensive. Additionally, most of the refineries are located in coastal areas with fog and cloud cover, reducing the effectiveness of solar generation. A solar project in a refinery setting would need to be a series of small projects to take advantage of open refinery land areas. The cost of these solar projects would be higher than other settings because of the necessary explosion-proofing and other requirements unique to the refinery setting.

3.2.2 High, Mid, and Low Refinery Renewable or Low-CI Electricity Credit Generation Possibilities

To develop the high, mid, and low LCFS credit estimates for renewable or low-CI electricity, we assumed different percentages of a typical refinery land area would be used for solar power generation and calculated the resulting solar power. We assumed a high scenario of 5%, mid scenario of 2% and low scenario of 0.5% of refinery land used for solar projects. Our resulting estimates for the 2030 high, mid, and low cases for renewable and low-CI electricity in refineries are displayed in Table 2.

Table 2. Possible Renewable and Low-CI Electricity LCFS Credits (MT per year)

High	Mid	Low
40,000	16,000	5,000

Compared to the unrestricted possibilities, the magnitude of these estimates is quite low since, unlike offsite renewable electricity, available land is limited.

3.3 Use of Low-CI Process Energy

CARB's draft proposed regulation includes the "use of lower-CI process energy such as biomethane, renewable propane, and renewable coke, to displace fossil fuel." Here, process energy is defined as any refinery energy used other than electricity generated or electricity or steam that is purchased.

Table 3 below lists EIA total energy consumption by energy source for PADD 5 refineries.[18] The highest carbon sources of energy (coal and marketable petroleum coke), have already been eliminated in all West Coast refineries. The next highest (residual fuel oil and crude oil), were also completely or nearly eliminated by the end of 2016. In fact, none of the residual oil used in PADD 5 is consumed in California. The vast majority of the remaining sources of energy are natural gas and still gas. Catalyst petroleum coke is a necessary byproduct of the conversion processes used to produce gasoline and diesel, so there is no opportunity to displace it with other energy sources.

[18] U.S. Energy Information Administration. Fuel Consumed at Refineries, PADD 5. June 21, 2017. https://www.eia.gov/dnav/pet/pet_pnp_capfuel_dcu_r50_a.htm

Table 3. Energy Consumed at PADD 5 Refineries

Year	Crude Oil	LPG	Distillate	Residual Fuel	Still Gas	Petroleum Coke	Marketable Petroleum Coke	Catalyst Petroleum Coke	Other Products	Natural Gas, Million SCF	Coal	Purchased Electricity (Million KWhours)	Purchased Steam (Million Pounds)
2005	0	2291	253	727	45700	15371	970	14401	1700	123271	0	4978	17956
2006	0	1468	255	770	44999	14550	110	14440	2199	126190	0	4973	17999
2007	0	1415	236	743	45553	14521	117	14404	1716	133713	0	5113	17838
2008	0	1509	292	745	43383	12360	103	12257	2027	139950	0	5125	17777
2009	0	1320	129	804	39475	11748	125	11623	1416	136221	0	4890	18687
2010	0	883	253	753	43737	10492	145	10347	1254	151808	0	4964	14030
2011	0	431	319	677	39284	11793	143	11650	1119	156599	0	5221	14349
2012	0	518	209	469	38875	12582	166	12416	1141	159849	0	5130	14426
2013	0	378	168	354	43734	12694	161	12533	1097	177103	0	4820	13143
2014	0	513	102	346	46065	12625	143	12482	733	186011	0	4705	13370
2015	0	846	110	333	44613	10981	90	10891	466	177513	0	4185	12939
2016	0	579	224	244	46604	12223	0	12223	514	184740	0	4529	13426

All units are thousands of barrels unless otherwise noted.

We know of no renewable coke in the marketplace and no announced plans to produce it at scale. Small amounts of liquefied petroleum gas (LPG) are produced in the production of renewable diesel (RD) and more would likely be created in the production of renewable gasoline (RG) at scale, but both RD and RG generate far more LCFS credits than LPG due to low LPG yield in the processes that produce those fuels. This means that the most likely source of renewable LPG production that would be used in a refinery would result from that refinery co-processing renewable feedstocks. This co-processing would be a small subset of an analysis of refinery co-processing capabilities, which is outside the scope of this study.

3.3.1 Unconstrained Possibility for Use of Low-CI Process Energy

If all the natural gas consumed in California refineries (about 60% of PADD 5 consumption) was replaced with biogas, approximately 5 million MT per year of fossil CO_2 emissions would be eliminated.

Biomethane (or biogas) production has been growing steadily in the U.S., and credits can be created from biogas via electricity, CNG and LNG, and/or hydrogen production. These credits are only limited by biogas supply. By far, selling biogas into CNG/LNG vehicles in California offers the highest credit value because it generates valuable cellulosic Renewable Identification Numbers (RINs) under the federal Renewable Fuel Standard (RFS), as well as LCFS credits. Additionally, that fuel would avoid almost all Cap and Trade costs of selling fuel at the rack. Until now, all biogas LCFS credits have been created through CNG and LNG sales. Biogas supply must exceed CNG and LNG demand in California before it will be used for process heaters, electricity generation, or hydrogen production. Biogas creates roughly the same value when used in these three applications if done in the refinery, but refineries would also have to compete with power companies for supply.

Prospects for biogas growth are good. The U.S. Environmental Protection Agency (EPA) forecasts a 21% increase in RINs from biogas between 2017 and 2018 based on recent year-on-year increases.[19] EPA also reported 215.5 million gallons of ethanol-equivalent energy supplied by biogas for the 12 months ending September 2017. Over the same period, CARB reported 100 million diesel gallon equivalents (DGE) of biogas use,[20] which is equivalent to approximately 170 million gallons of ethanol. California is attracting nearly 80% of the transportation biogas produced in the United States, which makes sense due to the additional value biogas generates in LCFS credits.

[19] U.S. Environmental Protection Agency. Renewable Fuel Standard Program: Standards for 2018 and Biomass-Based Diesel Volume for 2019. December 12, 2017. https://www.gpo.gov/fdsys/pkg/FR-2017-12-12/pdf/2017-26426.pdf
[20] California Air Resources Board. LCFS Quarterly Data Spreadsheet. January 31, 2018. https://www.arb.ca.gov/fuels/lcfs/dashboard/quarterlysummary/quarterlysummary_013118.xlsx

3.3.2 High, Mid, and Low Refinery Use of Low-CI Process Energy Credit Generation Possibilities

To develop the high, mid, and low LCFS credit estimates for low-CI process energy in refineries, we began by estimating biogas availability going forward by extrapolating recent historical trends in California as reported in the LRT quarterly data. For our low case, we assumed the average biogas CI is 40 grams per megajoule (gCO_2/MJ), and year-on-year growth decelerates to 10% per year in the middle of the next decade. For our middle case, we assume the average biogas CI is 35 g/mj and growth decelerates to 12% per year. For both cases, we assumed that CNG and LNG demand matching CARB's illustrative scenario calculator. (The calculations and resulting balances are shown in Appendices 1 and 2.) Our results show 1.5 and 1.0 million MT of biogas supply available into California in addition to that needed for CNG and LNG for the mid and low credit cases, respectively. We assumed 10% and 5% of what is available is used for process energy, respectively. Finally, we assumed that CARB's illustrative scenario represents the high case credit scenario. It shows 1.9 million MT of credits produced from renewable hydrogen in California refineries. We assume that process energy is 10% of this.

Given our educated assumptions, the summary of projections for each case is shown in Table 4.

Table 4. Possible Low-CI Process Energy LCFS Credits (MT per year)

High	Mid	Low
190,000	150,000	50,000

3.4 Electrification at Refineries

CARB's draft proposed LCFS regulation includes "electrification at refineries that involves substitution of high-carbon fossil energy input with grid electricity" as a project type eligible for refinery investment project credits. In refineries, two types of projects could generate credits by replacing high-carbon fossil energy input with grid electricity. The first type of project is replacing fired furnaces (which provide process heat or steam generation) with electric heating. A second type is to replace steam turbines with electric motors to reduce the generation of steam from combusting fossil fuels.

Refinery furnaces usually operate at high thermal efficiencies (80%) – higher than the efficiency to produce electricity from a thermal power station (approximately 35%). Replacing direct-fired heat with electrical power would increase CO_2 emissions unless the thermal efficiency of the direct-fired furnace is lower than grid electricity. Therefore, we do not expect that any LCFS credits will be generated by electric heat projects in refineries.

Depending on the philosophy under which a refinery was designed and built, that refinery may have either turbines or motors to drive its pumps. In the mid-20th century, when many of the refineries expanded to the equipment that operates today, steam turbines were often chosen in refineries for critical applications because grid electricity was not dependable, resulting in emergency shutdowns. In today's refinery operating environment, motors are preferred because of the lower initial and ongoing cost, and grid electricity is much more stable.

For refineries operating large steam turbine drivers, the total steam cycle efficiency (water to steam to steam power to water) is low. Under the right circumstances, there will be enough operating cost and LCFS credit incentives to replace steam turbines with electric motors.

3.4.1 Unconstrained Possibility for Refinery Electrification

Accurate information on the number and horsepower (HP) of steam turbines used in California's refineries is not available. In order to estimate the steam turbines, Stillwater applied its judgement of what processes in a typical refinery may have large pump and compressor drivers, and what percent of those may be driven by steam drivers. We estimate that a maximum of 130,000 HP is provided by steam turbine drivers. If all these steam turbine drivers were replaced by electric motors, approximately 700,000 MT of LCFS credits could be generated through RIC. Not all steam turbines would be candidates for switching because of high retrofit costs.

3.4.2 High, Mid, and Low Refinery Electrification Credit Generation Possibilities

The exact number of steam-turbine-to-electric-motor projects installed under RIC will depend on the particulars of the specific retrofit projects since the cost correlates to the specifics of the project and considerations such as whether steam can be reduced or used elsewhere. For these projects, the incentives created by generating LCFS credits is large, at two to three times the financial incentive from the operating costs savings, making this class of projects promising to implement.

For the high, mid, and low cases, we estimated that 100,000, 40,000 and 10,000 HP respectively will be converted from steam turbine drive to electric motors. Given these estimates, our summary of projections for each case is displayed in Table 5.

Table 5. Possible Electrification at Refineries LCFS Credits (MT per year)

High	Mid	Low
540,000	220,000	55,000

The accuracy of these estimates is speculative since specific data on the number and rated HP of steam turbines in California's refineries are not available.

3.5 Process Improvements

The draft proposed regulation includes "process improvement projects" resulting in CI "reductions per megajoule of total CARBOB and diesel produced." Process improvement credits cannot be generated after January 1, 2025; therefore, these projects will not contribute to credit generation in 2030 and will have no impact on CI reductions achievable at that time.

3.6 Renewable Hydrogen

The most practical source for generating renewable hydrogen is steam-reforming biomethane (biogas). LCFS credits from biogas, however, can also be created via electricity, CNG and LNG, and/or hydrogen. These credits are limited by biogas supply.

3.6.1 Unconstrained Possibility for Renewable Hydrogen

If there were no supply or technical issues, all refinery hydrogen could be produced from biogas. Total California refinery hydrogen plant production is approximately 1,100 million standard cubic feet per stream day. If all the carbon from producing this hydrogen were produced from biogas, roughly 5 million MT of credits could be produced per year.

3.6.2 3.4.2 High, Mid, and Low Renewable Hydrogen Credit Generation Possibilities

Since biogas availability is constrained by supply, we used the supply analysis described in section 3.3 and appendices 1 and 2 to assess what might be available for hydrogen production versus other uses. The nature of hydrogen production is such that almost all of it can be assumed to be from methane, while process energy is supplied in several other forms. Therefore, we assume more of the available biogas creates credits from hydrogen than process energy.

Results of our supply analysis in section 3.3 show 1.5 and 1.0 million MT per year of biogas supply available into California (in addition to what is needed for CNG and LNG) for the mid and low credit cases, respectively. We assumed 50% and 20% of what is available is used for hydrogen production energy, respectively. Finally, we assumed that CARB's illustrative scenario represents the high case credit scenario, although CARB's estimate seems unlikely unless biogas is not utilized in the power sector. Given these calculations and educated estimates, our summary of projections for renewable hydrogen is displayed in Table 6.

Table 6. Possible Renewable Hydrogen LCFS Credits (MT per year)

High	Mid	Low
1,900,000	750,000	200,000

4 Results and Conclusions

4.1 Factors Affecting RIC and RHRC Investment Decisions

As noted above, there are many factors that will affect the extent to which RIC and RHRC projects will proceed and succeed. These factors fall into several areas which we highlight here.

4.1.1 Regulatory Concerns

Several regulatory constraints could affect RIC and RHRC projects. The draft proposed regulation includes thresholds and limitations which could eliminate smaller projects. "Inside-the-meter" limitations for renewable electricity constrain the amount of renewable power available to a refinery because of acreage limitations. The 2025 sunset on credits produced through process improvements eliminates any LCFS incentive for these projects after that year. For refineries in Southern California, tightening limits under RECLAIM for nitrous oxides (NOx) will add incentives to reduce combustion in Southern California refineries. On the other hand, the value of Cap and Trade allowances is an added incentive to the LCFS credits for some of these projects. For fuels (such as biogas) that are covered under the RFS, the RINs that are generated also add to the value of the fuel. Decision-makers will have to consider each of these regulatory realities when determining whether to invest in an RIC or RHRC project.

4.1.2 Resource Availability Constraints

As discussed in section 3.3, biogas is limited due to its direct use as CNG or LNG for transportation, and that use puts it in direct competition with RIC and RHRC projects.

4.1.3 Refinery Design Constraints

Refineries vary greatly in their configuration and design. Generalized assumptions do not always accurately represent the specifics and the attractiveness of an RIC project for a given refinery. Furthermore, the cost of any project will vary from refinery to refinery because of the variation in configuration and design. These RIC projects involve retrofitting process units, requiring extended downtime and associated costs. Finally, other factors specific to a refinery may add to the incentive to install an RIC project. Examples of this are the need to replace equipment or enabling shutdown or replacement of older inefficient or costly equipment which increases the economic incentives.

4.2 Total RIC and RHRC Credit Predictions for 2030

Considering as many factors as possible, Stillwater has estimated high, mid, and low LCFS credits cases for 2030 from the RIC and RHRC provisions in the current and proposed LCFS regulatory text. These estimates represent fair values considering the short timeframe and lack of specific refinery information upon which to draw.

A summary of the total RIC and RHRC credits we envision being possible in 2030 is displayed in Table 7.

Table 7. Total 2030 Potential for RIC and RHRC

Project Category	LCFS Credits – MT CO_2/year		
	High	**Mid**	**Low**
Carbon Capture and Sequestration	2,000,000	730,000	365,000
Renewable Electricity	40,000	16,000	5,000
Low-CI Process Energy	190,000	150,000	50,000
Electrification	540,000	220,000	55,000
Process Improvement	0	0	0
Renewable Hydrogen	1,900,000	750,000	200,000
TOTALS	**4,670,000**	**1,866,000**	**675,000**
TOTALS without CCS	**2,670,000**	**1,136,000**	**310,000**

5 Profiles of Report Authors

Since 1997, **Stillwater Associates** has provided extensive transportation fuels expertise to clients in the downstream market. Our associates earned their years of experience at major international petroleum corporations. Our focus is on energy policy with an emphasis on traditional and next generation fuels refining, distribution, and marketing issues. *Stillwater Associates fuels the future of transportation energy with trusted industry experience.*

Leigh Noda, Senior Associate. Leigh has a broad-based experience in the petroleum refining, petroleum products, and alternate fuels arenas. His experience covers refinery operations, technology, business planning and strategy, business and project development, finance and EH&S (environmental, health and safety).

Over the course of 28 years at ARCO, Leigh held numerous positions including key positions during the period when many critical decisions and investments were made to the two west coast refineries to address new stationary source environmental and fuel standards. While he was manager of technology and business at Carson Refinery, ARCO developed the first environmentally reformulated fuel (EC-1) that was introduced to the market in 1989. The fuel was developed in collaboration with fuels and central technology groups to demonstrate that gasoline can be cleaner-burning and can be part of the future fuels mix of the country.

After ARCO, Leigh has consulted on a wide variety of projects ranging from development of investment opportunities for a private equity firm, to evaluation of the potential of innovative new technologies, to development of an innovative project for a GTL plant in Trinidad. In support of the US Agency for International Development he authored a white paper of US laws and regulations for use by Kazakhstan in development of their regulatory and environmental laws. Since 2010, Leigh has worked with Stillwater Associates across a broad range of studies with many projects in California's Low Carbon Fuel Standard arena.

Leigh earned a Master's in Business Administration from the UCLA Anderson School and a Bachelor of Science in Chemical Engineering from the University of California at Davis. His experience and education are the basis for strong analytical skills and an ability to address complex challenges and opportunities.

Jim Mladenik, Senior Associate. Jim spent 33 years at ARCO and BP before joining Stillwater Associates. His experience at BP covered all parts of the West Coast fuel value chain. He was instrumental in developing product placement, production, and marketing strategies; setting up the distillate trading book; and establishing wholesale diesel offers and military contract bids. Jim also developed BP's compliance strategies for California's Low Carbon Fuel Standard and Carbon Cap & Trade program and the federal Renewable Fuels Standard.

During his time at ARCO, Jim served as a technical specialist supporting the company's two West Coast refineries. In this capacity, he created one of the world's first comprehensive mathematical models of the delayed coking process. He later led the technical support team in the coking area which supplied a large calcined coke marketing business.

Jim earned his Bachelor's and Master's degrees in Chemical Engineering from the University of Notre Dame and an MBA from the University of California, Irvine.

Kendra Seymour, Analyst. Kendra is the editor of and a regular contributor to Stillwater's Low Carbon Fuel Standard Newsletters. Since joining Stillwater in 2014, she has offered research, editing, and process management expertise for numerous Low Carbon Fuel Standard and Renewable Fuel Standard projects. Kendra earned her Bachelor Arts in International Relations from Northwest Nazarene University.

APPENDIX 1. Low Case Biogas Calculations

	Low Case			Biogas CI = 40 g/mj		
	Biogas Available to California, million dge	**Year on Year Growth, %**	**Illustrative Scenario total CNG/LNG Demand, million dge**	**Excess Biogas, million dge**	**Ren H2 Credits Available, million MT**	**Illustrative Scenario total credits from Renewable H2**
2013	10					
2014	29	181%	29			
2015	69	141%	68			
2016	88	27%	87			
Est. 2017	107	21%	117			0.05
2018	128	20%	146			0.24
2019	151	18%	171			0.83
2020	175	16%	193			1.56
2021	200	14%	213			1.51
2022	226	13%	234			1.46
2023	253	12%	255			1.53
2024	281	11%	284			1.59
2025	309	10%	288	21	**0.11**	1.65
2026	340	10%	295	45	**0.24**	1.70
2027	374	10%	302	72	**0.39**	1.76
2028	411	10%	307	104	**0.56**	1.81
2029	452	10%	313	139	**0.76**	1.87
2030	498	10%	319	178	**0.97**	1.92

APPENDIX 2. Middle Case Biogas Calculations

	Middle Case			Biogas CI = 35 g/mj		
	Biogas Available to California, million dge	Year on Year Growth, %	Illustrative Scenario total CNG/LNG Demand, million dge	Excess Biogas, million dge	Ren H2 Credits Available, million MT	Illustrative Scenario total credits from Renewable H2
2013	10					
2014	29	181%	29			
2015	69	141%	68			
2016	88	27%	87			
Est. 2017	107	21%	117			0.05
2018	128	20%	146	(18)		0.24
2019	151	18%	171	(20)		0.83
2020	175	16%	193	(17)		1.56
2021	200	14%	213	(13)		1.51
2022	226	13%	234	(8)		1.46
2023	253	12%	255	(2)		1.53
2024	283	12%	284	(0)		1.59
2025	317	12%	288	29	0.18	1.65
2026	356	12%	295	61	0.37	1.70
2027	398	12%	302	97	0.59	1.76
2028	446	12%	307	139	0.85	1.81
2029	500	12%	313	186	1.14	1.87
2030	559	12%	319	240	**1.47**	1.92

Chris Bliley
18-3-3

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WANGER JONES HELSLEY PC
ATTORNEYS

OLIVER W. WANGER
TIMOTHY JONES*
MICHAEL S. HELSLEY
PATRICK D. TOOLE
SCOTT D. LAIRD
JOHN P. KINSEY
KURT F. VOTE
TROY T. EWELL
JAY A. CHRISTOFFERSON
MARISA L. BALCH
PETER M. JONES**
STEVEN M. CRASS**
AMANDA G. HEBESHA***
JENA M. HARLOS****
MICAELA L. NEAL
REBECCA S. MADDOX
NICOLAS R. CARDELLA
ERIN T. HUNTINGTON
STEVEN K. VOTE
JENNIFER F. DELAROSA
LAWRENCE J.H. LIU
ROCCO E. DICICCO
GIULIO A. SANCHEZ

* Also admitted in Washington
** Of Counsel
*** Of Counsel/Also admitted in Idaho
**** Also admitted in Wisconsin

265 E. RIVER PARK CIRCLE, SUITE 310
FRESNO, CALIFORNIA 93720

MAILING ADDRESS
POST OFFICE BOX 28340
FRESNO, CALIFORNIA 93729

TELEPHONE
(559) 233-4800

FAX
(559) 233-9330

WJH

OFFICE ADMINISTRATOR
LYNN M. HOFFMAN

Writer's E-Mail Address:
jkinsey@wjhattorneys.com

Website:
www.wjhattorneys.com

April 26, 2018

Via Hand Delivery

Clerk of the Board
CALIFORNIA AIR RESOURCES BOARD
1001 "I" Street, 23rd Floor
Sacramento, CA 95812

**Re: California Air Resources Board
April 27, 2018, Public Meeting, Agenda Item No. 18-3-5: Public Meeting to Consider Proposed Voluntary NOx Remediation Measure Funding**

Dear Madam Clerk:

I am submitting the following comments on behalf of Growth Energy, related to the California Air Resources Board's ("ARB") April 27, 2018, public meeting to Consider Proposed Voluntary NOx Remediation Measure Funding, Agenda Item No. 18-3-5.

The agenda for the April 27, 2018, meeting describes Agenda Item No. 18-3-5 as follows:

> The Board will consider approving a voluntary measure to provide immediate funding to air districts to achieve further reductions in emissions of oxides of nitrogen (NOx). This initiative arises from CARB's response to a 2017 court order in the ongoing POET litigation challenge to the 2009 adoption of the Low Carbon Fuel Standard (LCFS). This measure aims to remediate conservatively estimated historical emissions potentially related to increased use of biodiesel in California

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WANGER JONES HELSLEY PC

Clerk of the Board
April 26, 2018
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> that may be attributable to incentivization of biodiesel use by the LCFS regulation. The voluntary measure is consistent with CARB's mission to promote and protect public health and welfare through the effective and efficient reduction of air pollutants.

(April 27, 2018, Agenda, California Air Resources Board.)[1]

Growth Energy supports the notion that CARB should mitigate estimated historical NOx emissions that were incentivized by the LCFS regulation. Growth Energy likewise supports the funding of local projects in the geographic areas most directly affected by such increased NOx emissions. B4-1

However, because this measure appears to be related to mitigation identified in the Initial Statement of Reasons, Appendix G, for the proposed amendments to the low carbon fuel standard (the "LCFS"), it should be considered concurrently with the rulemaking process for the amendments. This is necessary to ensure the proposed mitigation will be efficacious, and consistent with the requirements of the California Environmental Quality Act, Pub. Resources Code, § 21000, *et seq.* ("CEQA"), and that segmentation of the environmental review process would not occur. B4-2

Moreover, because the agenda did not include a staff report, and Agenda Item No. 18-3-5 does not include a complete description of the proposed action, there are several questions regarding the proposed action that relate to its adequacy as a mitigation/remedial measure for historical NOx emissions that should be answered before CARB considers this item:

- What is the amount of NOx CARB intends to mitigate through the program?
- How will local projects be selected for receipt of funding?
- How will CARB confirm selected local projects will reduce NOx emissions in a way that would offset the impacts associated with historical NOx emissions from biodiesel use on a ton-for-ton basis? B4-3
- How will CARB allocate funding between the various local air districts that would receive funding from the program, and what is the nexus between any such allocation and the historical NOx emissions from biodiesel use?
- What is the source of funding for the program?

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1 The agenda does not include a link to the Staff Presentation, which the website states will not be available under the time the item is heard. (Exhibit "A.")

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WANGER JONES HELSLEY PC

Clerk of the Board
April 26, 2018
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- To the extent a funding source has been identified, (i) what efforts have CARB made to ensure the funding is adequate to reduce historical NOx emissions from biodiesel use, and (ii) what evidence supports any such conclusion?

- Does CARB contemplate separately reporting in a publicly available manner the expenditures it makes under the program to mitigate historical NOx emissions from biodiesel use? How will any such information be made available to the public?

B4-3 cont.

I look forward to your response to each of the above questions. Thank you for your attention to this matter.

Respectfully submitted,

John P. Kinsey

Enclosures

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EXHIBIT "A"

THE CARB SLIDE PRESENTATION WILL BE AVAILABLE THE DAY OF THE BOARD MEETING AT THE TIME THE ITEM IS HEARD.

growth energy™
America's Ethanol Supporters

701 8th Street, NW, Suite 450, Washington, D.C. 20001
PHONE 202.545.4000 FAX 202.545.4001
GrowthEnergy.org

April 26, 2018

By Electronic Mail
Clerk of the Board
California Air Resources Board
1001 I Street, 23rd Floor
Sacramento, California 95812

Re: Proposed Amendments to the California Low-Carbon Fuel Standards Regulation and the Regulation on the Commercialization of Alternative Diesel Fuels

Dear Madam:

Growth Energy, an association of the nation's leading ethanol manufacturers and other companies who serve the nature's need for alternative fuels, is submitting to you the enclosed materials in response to the notice of proposed amendments to California Low-Carbon Fuel Standards Regulation and the Regulation on the Commercialization of Alternative Diesel Fuels. These materials also include environmental comments being submitted to the Air Resources Board and the Executive Officer pursuant to the California Environmental Quality Act and the Board's implementing regulations.

Growth Energy may file additional materials in one or both rulemaking files for consideration in connection with this agenda item at a later time, as permitted by the California Government Code and the Public Resources Code.

If there are logistical questions concerning these submittals, please contact Mr. John P. Kinsey of Wanger Jones Helsley PC at 559-233-4800.

Thank you for your consideration and assistance.

Sincerely,

Chris Bliley
Vice President of Regulatory Affairs
Growth Energy

Page 1 of 1

STATE OF CALIFORNIA
AIR RESOURCES BOARD

PROPOSED AMENDMENTS TO THE LOW CARBON FUEL STANDARD REGULATION AND TO THE REGULATION ON COMMERCIALIZATION OF ALTERNATIVE DIESEL FUELS

GROWTH ENERGY'S RESPONSE
TO THE NOTICE OF PUBLIC HEARING DATED FEBRUARY 20, 2018
2018 CAL. REG. NOTICE REG.10Z, 392 (MARCH 9, 2018)

APRIL 27, 2018

For further information contact:
Mr. Chris Bliley
Vice President of Regulatory Affairs
Growth Energy
CBliley@growthenergy.org
202-545-4000

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Comments of Growth Energy on the Proposed Amendments to the Low Carbon Fuel Standard Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels

Growth Energy respectfully submits these comments on the proposed amendments to the low carbon fuel standard ("LCFS") regulation and the regulation on commercialization of alternative diesel fuels ("ADF"). Growth Energy is an association of the leading ethanol producers in the United States and other companies that serve America's need for renewable fuels. Growth Energy promotes the use of alternative fuels to reduce transportation-sector greenhouse gas emissions and consumer costs, among other benefits.

Growth Energy's comments to the California Air Resources Board ("CARB" or, the "Board") on the proposed modifications to the LCFS and ADF regulations (collectively, the "Proposed Amendments") are contained in this summary document, which includes several appendices and exhibits that provide an extended analysis of certain issues.

As an initial matter, Growth Energy would like to thank CARB staff for recommending several amendments to the LCFS regulation that update the scientific basis of the program, particularly with respect to the calculation of the carbon intensity ("CI") for corn starch ethanol. Since CARB first considered the LCFS regulation for adoption, Growth Energy has expressed concern that the CI for corn ethanol is too high – particularly with the incorporation of land use change ("LUC") impacts – and that the CI for Brazilian sugarcane ethanol is too low. While more work is needed, Growth Energy recognizes the Proposed Amendments show progress on CARB's part in aligning the treatment of corn starch ethanol and sugarcane ethanol with "the best available economic and scientific information . . . ." (Health & Saf. Code, § 38562, subd. (e).) B4-4

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That said, Growth Energy remains concerned about several aspects of the LCFS regulation and the ADF regulation, which CARB should address in the instant rulemaking. To assist CARB with these efforts, Growth Energy offers the following comments, which are summarized as follows:

Part I of these comments summarizes the Statutory Framework applicable to CARB's consideration of the Proposed Amendments, and discusses the various procedural steps that must be taken prior to the Board's consideration of the Proposed Amendments for approval.

Parts II and III of Growth Energy's comments address the governing statute, the Global Warming Solutions Act ("AB 32") as it applies to this rulemaking; the California Administrative Procedure Act, Govt. Code, § 11350, *et seq.* (the "APA"); and other statutes. This portion of the comments addresses, *inter alia*, the duty to analyze regulatory alternatives under the APA; the Standardized Regulatory Impact Assessment (or "SRIA") prepared for the Proposed Amendments; the external peer review process required under Section 57004 of the Health & Safety Code; AB 32's requirement to ensure no increase in criteria pollutant emissions would occur as a result of the LCFS regulation and the Proposed Amendments; and the requirement to provide a complete rulemaking file available to the public.

Part IV addresses the California Environmental Quality Act, Pub. Resources Code, § 21000, *et seq.* ("CEQA"), including the duty to analyze and mitigate NOx emissions that must be attributed to the LCFS program; the analysis of new or modified facilities that would be constructed as a result of the LCFS regulation; the unintended but still adverse effects of "fuel shuffling"; the discussion of alternatives to the Proposed Amendments (and the LCFS B4-11

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2

regulation); the estimated CI for various alternative fuels; and the mitigation measures proposed in CARB's functional equivalent environmental document.[1]

B4-11 continued from above, continues to footnote below

I. STATUTORY FRAMEWORK AND BACKGROUND

As a rulemaking subject to the California Administrative Procedure Act, (Govt. Code, § 11340, *et seq.*), the Proposed Amendments must be demonstrated to be consistent with and reasonably necessary to accomplish the purposes of AB 32 and SB 32, which codifies a statewide greenhouse gas target of at least 40 percent below 1990 levels by 2030. (Govt. Code, § 11342.2; see also Health & Saf. Code, § 38500, *et seq.*)

Several provisions of AB 32 are important to determine whether the LCFS is consistent with and reasonably necessary to accomplish the purposes of SB 32 and AB 32. First, regulations to implement AB 32 must not "interfere with . . . efforts to achieve and maintain federal and state ambient air quality standards" to the extent feasible, in addition to being adopted in a manner that complies with CEQA. (Health & Saf. Code, § 38562, subd. (b)(4).) In addition, the emissions reductions that CARB attributes to a regulation promulgated under AB 32 must be "real, permanent, quantifiable, verifiable and enforceable." (*Id.*, § 38562, subd. (d)(1).)[2] Moreover, AB 32 directs that the Board "shall" rely upon "the best available economic and scientific information" when adopting regulations to implement AB 32. (See Health & Saf.

B4-12 continues to footnote below and next page

1 Each Appendix enclosed herewith is a part of Growth Energy's comments. Consistency with the APA requires a full and complete response to each objection and recommendation in the appendices to the main text of these comments, regardless of whether those objections or recommendations are discussed in the main text of these comments, or explain why those objectives or recommendations are "irrelevant." (See Govt. Code, § 11346.9, subd. (a)(3).) To ensure compliance with that requirement of the Government Code, California courts will conduct de novo review using independent judgment. (Cf. *POET LLC v. California Air Resources Bd.* (2013) 218 Cal.App.4th 681, 747-48.) Particularly when the facts concerning CARB's actions in the regulatory process cannot be a subject of genuine dispute, "the independent standard of appellate review" applies. (*Id.* at 748.)

B4-11 continued from above

2 Notably, the requirements in subsection (d) of section 38562 are not qualified by the limitation in subsection (b), *i.e.*, "to the extent feasible."

B4-12 continued from above

Code, § 38562, subd. (e).) AB 32 also mandates that any "market-based compliance mechanism" – such as the LCFS regulation – must be designed "to prevent any increase in the emissions of . . . criteria air pollutants." (Health & Saf., § 38570(b)(2).) For the reasons explained in these comments and the appendices, the proposed amendments to the LCFS regulation are not currently consistent with these provisions of AB 32. B4-12 cont.

The APA also contains several other requirements to (i) help avoid potential unintended consequences of a regulation, (ii) promote informed decision-making, and (iii) ensure public participation in the rulemaking. For example, the APA prohibits state agencies from proposing regulations unless they have determined no alternative to their own proposal would be "as effective and less burdensome to affected private persons and equally effective in implementing the statutory purpose or other provision of law." (Govt. Code, § 11346.5, subd. (a)(13).) Thus, a state agency may not adopt a proposal unless it can properly affirm and explain, with "supporting information," that "no alternative" it has considered "would be more effective and less burdensome to affected private persons than the adopted regulation, or would be more cost effective to affected private persons and equally effective" in meeting the proposal's legislative objective. (*Id.*, § 11346.9, subd. (a)(4).) B4-13

As explained below, in response to a public solicitation for alternatives by CARB, the Western States Petroleum Association ("WSPA") submitted a proposed alternative to the LCFS regulation under which GHG emissions currently attributable to the LCFS program would "instead be achieved by the Assembly Bill (AB) 32 Cap and Trade program in the most cost-effective manner to address GHG emissions." (EA at 207; see also ISOR at IX-1.) Although WSPA states this alternative would avoid many of the potential adverse consequences of the LCFS regulation – including significant and unavoidable environmental effects; an increase in B4-14 gasoline prices by $0.36/gallon; over 25,000 lost jobs by 2030; and a 0.1% decline in California's Gross Domestic Product (GDP) – the ISOR does not consider any alternative other than variations of the LCFS. Growth Energy asks that, consistent with the APA, CARB fully consider the WSPA Alternative, or explain why it is choosing not to and provide the public with requisite opportunity for notice and comment with respect to that reasoning.[3]

B4-14 continued from previous page, continues to footnote below

The APA likewise directs state agencies to perform an assessment of "the potential for adverse economic impact on California business enterprises and individuals," (Govt. Code, § 11346.3, subd. (a)), and declare in the notice of proposed action any initial determination that the action will not have a significant statewide adverse economic impact directly affecting business. (Govt. Code, § 11346.5, subd. (a)(8); *Western States Petroleum Assn. v. Bd. of Equalization* (2013) 57 Cal.4th 401, 428 ["*WSPA*"].) The APA requires that the SRIA evaluate several issues, including "elimination of jobs within the state," "the elimination of existing businesses within the state," and "[t]he competitive . . . disadvantages for businesses currently doing business within the state." (Govt. Code, § 11346.3, subds. (c)(1)(A)-(C).) Here, while the SRIA includes several figures regarding the adverse economic impacts of the LCFS, the SRIA does not explain how these negative impacts will affect existing businesses; rather, the SRIA merely states there will be no change in competitive advantage or disadvantage based on the assumption that other states could adopt versions of the LCFS. If the Executive Officer adds such an explanation now, including by way of testimony or presentations to the Board, or other communications, the requirements of Section 11347.1 (a) would apply.

B4-15

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3 See Govt. Code, § 11347.1 subds. (a), (b). This would apply, for example, to an explanation included in testimony or presentations to the Board by the Executive Officer or staff (hereinafter, "the Executive Officer"), or to an ex parte communication by the Executive Officer to the Board.

B4-14 continued from above

The APA also requires transparency so that the public can participate effectively in the rulemaking process. (See, e.g., Govt. Code, § 11347.3; Health & Saf. Code, § 39601.5.) The APA thus obligates the agency to prepare and maintain a rulemaking file. (Govt. Code, § 11347.3.) These provisions require that the public have the same access to all the data and analysis used by an agency in developing regulations, as well as all external input provided to an agency in connection with the adoption or amendment of a regulation. In this case, the rulemaking file does not appear to have been made "available to the public for inspection" at the time when the first notice of the proposed rulemaking was published in the California Regulatory Notice Register, (*id.*, subd. (a)), which occurred in this proceeding on March 9, 2018. Growth Energy is also concerned the rulemaking file does not contain the documents required under Section 11347.3 of the Government Code. B4-16

In addition to complying with the APA, CARB must also commission peer reviewers to evaluate the "scientific portions" of the rule. (Health & Saf. Code, § 57004(d).) Specifically, Section 57004 of the Health & Safety Code requires that: (1) CARB "submit[] the scientific portions of the proposed rule, along with a statement of the scientific findings, conclusions, and assumptions on which the scientific portions of the proposed rule are based and the supporting scientific data, studies, and other appropriate materials, to the external scientific peer review entity for its evaluation," and (2) the peer reviewer "prepare[] a written report that contains an evaluation of the scientific basis of the proposed rule." (*Id.*, subd. (d).) Section 57004 of the Health and Safety Code defines the "scientific portions" of a proposed rule to include "those foundations of a rule that are premised upon, or derived from, empirical data or other scientific findings, conclusions, or assumptions establishing a regulatory level, standard, or other requirement for the protection of public health or the environment." (*Id.*, subd. (a)(2).) It is not B4-17 clear whether CARB has sought external peer review to evaluate the scientific portions of the rule, consistent with Section 57004, and if so, what steps CARB will take to permit adequate public review and comment. Parties attempting to comply with the Executive Officer's request in the Notice of Public Hearing that comments be sent to him several days before the scheduled hearing have no means to review and comment on peer review materials not yet published. B4-17 cont.

Moreover, the California Environmental Quality Act, Pub. Resources Code, § 21000, *et seq.* ("CEQA"), and its regulations governing the environmental review process require compliance. (See 17 Cal. Code Regs., § 60005–60007.) Generally speaking, CEQA directs that, prior to approving the Proposed Amendments, CARB must first "identify the environmental effects of projects, and then to mitigate [any] adverse effects through the imposition of feasible mitigation measures or through the selection of feasible alternatives." (*Sierra Club v. State Bd. of Forestry* (1994) 7 Cal.4th 1215, 1233.) B4-18

As a state agency, CARB has adopted a certified regulatory program under which it is exempt from some provisions of CEQA. Nevertheless, agencies with certified programs like CARB's must prepare a functional[ly] equivalent environmental document that "include[s] '[a]lternatives to the activity and mitigation measures to avoid or reduce any significant or potentially significant effects that the project might have on the environment.'" (*City of Arcadia v. State Water Resources Control Board* (2006) 135 Cal.App.4th 1392, 1422 [quoting CEQA Guidelines, § 15252(a)(2)(A)].) CARB's functional equivalent document is the "staff report," which "shall be prepared and published by the staff of the state board." (17 Cal. Code Regs., § 60005(a).) Any action "for which significant adverse environmental impacts have been identified during the review process shall ***not*** be approved or adopted as proposed if there are feasible mitigation measures or feasible alternatives available which would substantially reduce B4-19 such adverse impact." (*Id.*, § 60006.) If CARB receives comments raising "significant environmental issues associated with the proposed action," staff must "summarize and respond to the comments either orally or in a supplemental written report. Before taking final action on any proposal for which significant environmental issues have been raised, the decision maker shall approve a written response to each such issue." (*Id.*, § 60007.) As explained below in Part IV, Growth Energy believes further work is needed before the Proposed Amendments can be considered for Board action. B4-19 cont.

II. REGULATORY ANALYSIS

The Legislature has directed that programs like the LCFS regulation rely on the "best available economic and scientific information." (See Health & Saf. Code, § 38562, subd. (e).) This mandate includes CARB's use of lifecycle analysis ("LCA") in assessing greenhouse gas emissions under the LCFS regulation, the creation of carbon intensity ("CI") values assigned to various renewable fuels in the LCFS regulation,[4] and all other parts of the rulemaking.

The use of the most scientifically defensible CI values is critical to the rulemaking effort. The CI values provide what the 2009 Initial Statement of Reasons ("2009 ISOR") for the LCFS regulation called "signals" to the downstream oil industry. Those "signals" direct regulated entities to achieve reductions in the CI of the fuels they sell in the most cost-effective manner. Insofar as the intent of the LCFS regulation is to reduce GHG emissions, the regulation must establish "the maximum technologically feasible and cost-effective" method of doing so. (Health & Saf. Code, § 38561, subd. (a).) If the CI values send the wrong "signal" to the downstream regulated parties, then the LCFS regulation will result in the use of pathways that B4-20

4 The Legislature has not directed CARB to use CI as a regulatory mechanism; that is a choice the Board made in the 2009 LCFS regulation and that the CARB staff proposes to continue.

may increase GHG emissions above the levels that would result if the best possible CI values had been assigned to various renewable-fuel pathways in the regulation. As one witness affiliated with the University of California stated at the April 2009 Board hearing on the LCFS regulation:

> [I]f we make a mistake in one direction in estimating these numbers, we'll use too much of a biofuel that's actually higher carbon [than] we thought and will therefore increase global warming. And if we use numbers that are too low, then we'll use too little of a biofuel that's lower carbon than we thought and will therefore increase global warming.

(Transcript of Public Meeting of the Air Resources Board, April 23, 2009, at 73-74.) B4-20 cont.

As explained below, the "signals" that CARB's new California GREET 3.0 and indirect land-use change models provide for corn-starch, corn-stover, sugarcane ethanol, and electricity do not reflect the best available scientific and economic information, and therefore do not provide the "signals" to the downstream industry needed to maximize reductions in greenhouse gas emissions while minimizing costs. Put in terms of the above quote: the "numbers" for sugarcane ethanol and electricity are "too low," and the "numbers" for corn starch ethanol are "too high." As a result, "too little" corn-starch and corn-stover ethanol would be used in California gasoline under the Proposed Amendments. B4-21

In addition, if the Proposed Amendments were to be adopted, fuel shuffling would continue to occur. The evidence, for example, shows the LCFS program is simply causing entities to reorganize their delivery patterns, with no reduction in output from its high-CI facilities (which are now simply delivering to states other than California), and no increase in production from low-CI facilities (which are delivering to California in higher volumes). (See Appendix "C.") B4-22

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A. Calculation of Direct Emissions from Corn Ethanol & Sugarcane Ethanol [CA-GREET 3.0]

To calculate the CI value assigned to a fuel's direct greenhouse emissions under the LCFS regulation, the Executive Officer uses the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model, as staff has modified it for use in California (the "CA-GREET"). Recently, the developer of the GREET model, Argonne National Lab, published a new version of the GREET model: "GREET 2016." (ISOR at III-76.) CARB staff has developed a new version of the GREET model for the LCFS regulation (which the ISOR refers to as ("CA-GREET 3.0"), and through the Proposed Amendments seeks to incorporate CA-GREET 3.0 into the LCFS regulation. (*Id.*)

In Appendices D and F, Growth Energy comments on the portions of CA-GREET 3.0 used in CARB staff's new LCFS proposal to generate direct-CI values pertaining to corn and sugarcane ethanol. The following are among the issues that must be addressed adequately, with explanations to be included in the rulemaking file:

- GREET 2016 includes a distillers' grains methane credit, which is not included in CA-GREET 3.0. Growth Energy understands this credit was not included based on the belief that DGS (distillers grain with solubles) was included in livestock ratios in LCFS ethanol pathways, and that the animals consuming the DGS are not currently in the LCFS LCA ethanol system boundary. That position, however, is inconsistent with CARB's issuance of a pathway under the LCFS for methane produced from livestock manure where the pathway is allowed a substantial credit for methane avoidance similar to the methane avoidance credit for DGS. That position is also inconsistent with ISO LCA standard 14044, which B4-23a

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addresses environmental impacts throughout a product's life cycle (*i.e.*, cradle to grave). To ensure the methane credits are consistently applied throughout the LCFS regulation, and that CA-GREET 3.0 is consistent with ISO LCA standard 14044, the distillers' grains methane credit in GREET 2016 should be included in CA-GREET 3.0. (See Appendix D.) B4-23a cont.

- CA-GREET 3.0 includes values for energy use per ton-mile for medium-duty trucks that are lower than those for heavy-duty trucks. This is not logical, and it thus appears CA-GREET 3.0 (and GREET 2016) have overestimated the fuel use for medium duty trucks. (See Appendix D.)
- CA-GREET 3.0 overstates transportation emissions because it presumes the load size for heavy duty trucks in CA-GREET 3.0 is 15 tons. This value is too low; a typical value is 20 tons for a heavy duty truck. (See Appendix D.) B4-23b
- CA-GREET 3.0 also overstates transportation emissions because it uses the same energy per ton-mile for delivery as the return trip (backhaul), even though the load on return trips is reduced (approximately 50%). (See Appendix D.)
- By the mid-2020s, the ISOR estimates that the CI for corn ethanol will drop from approximately 70 g/MJ to 45 g/MJ. While significant reductions in CI could be achievable through new innovative fuels such as fuels derived from corn fiber, CARB has not yet acted on any such proposals. As a result, Growth Energy urges CARB to swiftly consider the approval of the proposed pathways for such fuel to help provide B4-23d

evidentiary support for CARB's 45 g/MJ estimate. In addition, Growth Energy understands the 45 g/MJ figure derives from an assumption that corn ethanol facilities would install carbon capture and sequestration ("CCS") at a rate of approximately 150 million gallons per year. It is unclear what evidence the Executive Officer relied upon to determine corn ethanol facilities would install CCS systems at the rate necessary to reduce their CI to 45 g/MJ.[5]

B4-23d continued from last page, continues to footnote below

- CA-GREET 3.0 understates the CI for sugarcane ethanol because the quantity of nitrogen in sugarcane in aboveground residues has been set to the lowest value found in literature. This value, however, is based on a 2007 study, which has been superseded by more recent studies, including Leite (2016), which concluded the quantity of nitrogen is much higher. (See Appendix D.)
- CA-GREET 3.0 also does not include nitrogen in the roots of sugarcane, which likewise understates the CI for sugarcane ethanol. (See Appendix D.)
- The Virtual Sugarcane Biorefinery (VSB) modeling system (Bonomi et al, 2016) shows that the CI for sugarcane ethanol in CA-GREET 3.0 is also understated because it underestimates nitrogen levels in synthetic fertlizers. (See Appendix D.)

B4-23e

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5 This apparent omission is one of the reasons why Growth Energy is concerned that the public rulemaking file is not complete.

B4-23d continued from above

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- When each of the above issues is taken into consideration, the CI for the sugarcane ethanol pathway should be increased from 51.11 to 55.89. (See Appendix D.) B4-23e cont.
- There are several errors in the existing Tier 1 simplified calculators under the CA GREET 3.0 model for sugarcane and corn ethanol. (See Appendix F.) B4-23f

In the past, the Executive Officer has sometimes indicated that important issues like those listed above with respect to CA-GREET can be deferred to a later proceeding. Growth Energy respectfully submits that deferral of the above issues and others explained in Appendix D would not comply with AB 32 or CEQA, as it would defer analysis and mitigation, and the consideration of feasible alternatives. B4-23g

B. Calculation of Indirect Land Use Emissions

One of the most significant aspects of the LCFS program has been the regulation's incorporation of the specific theory of indirect land-use change ("ILUC").[6] By incorporating ILUC into the LCFS regulation, CARB remains bound by AB 32, as well as its obligation to use the "best available" scientific and economic information under the APA. In each iteration of the rulemaking, Growth Energy has commented that the ILUC factor for corn ethanol is too high. In each subsequent iteration of the of the LCFS regulation, Growth Energy's comments have proven accurate, and the ILUC has been lowered significantly. Despite this, CARB staff has continued to ignore efforts by stakeholders, such as Growth Energy, to improve the quality of CARB's ILUC and indirect-emissions models, as well as recommendations of the Expert B4-24

6 It remains Growth Energy's position that the ILUC theory and the methods used to quantify the impacts of biofuel usage on land change, as well as the emissions model used by CARB to estimate emissions from land change, are too unreliable for use in regulation.

Working Group ("EWG") that CARB established when it first adopted the LCFS regulation. The consensus among technical experts is that these ILUC values remain overstated, and should be further reduced. (Appendix E.)

The APA requires either the adoption of each of the recommendations presented in Appendix E, and in Growth Energy's other appendices to these comments, or an adequate explanation of the reasons for not doing so, which must be made available for public review and comment prior to Board consideration. (See Govt. Code, §§ 11346.9, subd. (a)(3), 11347.1, subds. (a), (b).) In the text below, Growth Energy summarizes some of the key issues in the Executive Officer's new ILUC analysis:

B4-24 cont.

- The consensus among technical experts is that an ILUC for corn ethanol of 19.8 g/MJ is too high; rather, current estimates for the ILUC of corn ethanol in the U.S. range from 7.8-12 g/MJ. (Appendix E.)
- Although the ISOR at III-86 suggests that "[s]taff has not observed sufficient evidence in the literature to justify modifying the LUC CI values for the proposed regulation," significant work has been performed by Babcock and Iqbal at the University of Iowa, which shows significantly less global land conversions due to biofuel policies than previously thought and estimated by the CARB staff. Notably, this work has been reviewed extensively by Global Trade Analysis Project (GTAP) researchers at the University of Purdue, which was published in a peer-reviewed journal publication in July of 2017. (Appendix E.)

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- The current ILUC for corn ethanol does not accurately reflect the best available evidence, because it is based on year 2011 conditions, a drought year in the US, which negatively impacted crop yields.
- Because higher yields mean that less land use change is required to satisfy the new demand resulting in lower ILUC values, the use of 2011 conditions overstates ILUC significantly. (Appendix E.)

B4-24 cont.

C. Treatment of Electricity under the LCFS Regulation

The LCFS uses an "Energy Economy Ratio" ("EER") to account for differences in energy efficiency among different types of fuels and vehicles. "The EER is defined as the ratio of the number of miles driven per unit energy consumed for a fuel of interest to the miles driven per unit energy for a reference fuel." (2009 ISOR at ES-18.) Growth Energy has evaluated the development of the EERs, and has determined that several corrections should be made:

- The Chassis dynamometer ("dyno") tests used to develop the EERs were "conducted with all accessories off and at an ambient temperature of 70 to 75 F, which are conditions where EER for electric vehicles may be the highest. Because these conditions may be experienced for only short periods of time in much of California, EER values developed from dyno test data do not reflect real world conditions for much of the time such vehicles will be operating." (Appendix B at 2-3.; see also *id.* 4-6, 7.) Instead, the EERs should be based on testing performed under real world conditions, including performance under a greater variety in temperatures.

B4-25a

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- The efficiency of conventional gasoline and diesel engines that form the baseline for comparison for developing EERs are understated. (Appendix B at 3.) B4-25b
- The EER for CNG and propane engines was assumed to be 1.0; however, "the tanks used for propane and CNG fuel are quite heavy and a CNG tank capable of providing over 200 miles range can weigh over 250 lbs. which is a significant weight increase." (Appendix B at 3; see also *id.* at 7.) This weight increase causes the net EER to decline to 0.9. B4-25c
- The ISOR does not consider modifications to the EER required to accurately characterize electric drivetrain and battery losses. (Appendix B at 4.) B4-25d
- Because "accessory loads are not switched on during dynamometer testing," and "increased loads on the battery make it less efficient," the EERs for electric vehicles are underestimated. (Appendix B at 4.) B4-25e
- The EER for fuel cell vehicles is overestimated. (Appendix B at 6.) B4-25f
- The test cycles used for the track tests of LPG buses and trucks "do not resemble normal driving in that the cycles consist of a simple pattern of steady accelerations cruise at constant speed, and steady deceleration to idle," which would decrease the EER. (Appendix B4-25g

B at 7-8.) The same issue exists for electric trucks and buses. (Appendix B at 10-12.) B4-25g cont.

- The EER for transport refrigeration units is overestimated. (Appendix B at 9.) B4-25h
- Because the method of testing electric motorcycles included a very slow speed test with gentle accelerations and stops, this is unlikely "to represent the driving cycle for most motorcycle owners," resulting in an overstatement of the EER for electric motorcycles. (Appendix B at 9-10.) B4-25i
- As summarized on page 13 of Appendix B, numerous EERs used under the LCFS should be adjusted downward to more accurately reflect the evidence. (Appendix B at 13.) B4-25j

In sum, the CI values assigned to corn ethanol, sugarcane ethanol, and electricity are not based on "best available economic and scientific information," reliable data and methodologies, and need to be corrected before CARB tries to move forward with the Proposed Amendments. B4-25k

D. Treatment of Renewable Electricity for Fuel Pathways

We understand CARB staff has proposed amendments to "expand opportunities for accounting for renewable/low-CI electricity used in zero emission vehicle (ZEV) applications," as CARB states it has "seen very little interest in such pathways under the current rule." (ISOR at EX-4–EX-5.) As a result, the ISOR "proposes to allow renewable power generated in the same balancing authority as the ZEV load to be used in EV charging and H_2 production."[7] (*Id.* at EX-5.) In other words, to receive credit for renewable electricity associated with electricity B4-26

7 A map of California Balancing Authorities is located on the California Department of Energy's website: http://www.energy.ca.gov/maps/serviceareas/balancing_authority_areas.pdf

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usage, reporting entities need not demonstrate the source of the renewable electricity is co-located with the charging station. (See *id.*)

The text of the existing LCFS regulation appears to allow renewable fuels to receive credit for renewable electricity, regardless of whether the plant is co-located with the source of the renewable electricity:

> No indirect accounting mechanisms, such as the use of renewable energy certificates, can be used to reduce an energy source's CI. Innovative, low-CI energy sources include, but are not limited to renewable electricity ***from a dedicated (non-grid) form of generation***, such as wind turbines and photovoltaic arrays.

(See 17 Cal. Code Regs., § 95488(b)(2)(F)(1) [emphasis added].) In other words, so long as the "renewable electricity" is a "dedicated" form of generation, credits are available. B4-26 cont.

This is confirmed in CARB's regulatory guidance, which states:

> Electricity from a renewable energy source utilized in a fuel pathway may only be included in the CI determination if the energy from that source is directly consumed in the production process. No indirect accounting mechanisms, such as the use of Renewable Energy Certificates (RECs), can be used in determining the CI from electricity consumption. The applicant must provide evidence that the generation source is dedicated, generally by showing that the source is onsite/co-located, ***or was developed by the fuel producer with the sole intention of providing renewable power to the fuel pathway.***

(*Guidance Documents and FAQs* [emphasis added].)[8] In other words, under the existing regulation, the applicant need only "provide evidence that the generation source is dedicated." (*Id.*) And while that standard is generally satisfied through evidence of co-location, the guidance materials suggest credits may also be received if the renewable electricity source was "developed by the fuel producer with the sole intention of providing renewable power to the fuel pathway." (*Id.*)

[8] https://www.arb.ca.gov/fuels/lcfs/guidance/guidance.htm

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This position makes sense, as it would be counter-productive to the goals of AB 32 and SB 32 if the LCFS program were to distinguish between co-located and other dedicated renewable energy production when both reduce carbon emissions and promote innovation at fuel production facilities (as long as concerns such as additionally and the like are adequately addressed).

Unfortunately, however, the Proposed Amendments seek to delete Section 95488(b)(2)(F)(1), and replace the provision with new requirements governing renewable or low-CI process energy. (See ISOR, Appendix A at 155, *et seq.*) Those provisions appear to restrict the reduction of CI to those facilities that are co-located with the production facility:

> The generation equipment [must be] directly connected through a dedicated line to a facility ***such that the generation and the load are both physically located on the customer side of the utility meter.*** The generation source may be grid-tied, but a dedicated connection must exist between the source and load.

B4-26 cont.

(*Id.* at 156 [emphasis added].)

Growth Energy urges CARB to reconsider these amendments, and clarify that the CI of a pathway may be reduced if the fuel provider is able to demonstrate the dedicated use of renewable electricity as process energy, regardless of whether the generation equipment is specifically co-located with the facility. As an initial matter, this would align the treatment of electricity under the LCFS with the production of other renewable fuels. In addition, reconciling the treatment of electricity and other renewable fuels would help CARB meet the objectives of SB 32, which codifies a statewide greenhouse gas target of at least 40 percent below 1990 levels by 2030. (Govt. Code, § 11342.2; see also Health & Saf. Code, § 38500, *et seq.*; see also ISOR at EX-5 [stating the goal of "incent[ing] the installation of additional low carbon electricity supply" would result in greater greenhouse gas benefits].) It would also achieve CARB's goal of being fuel-neutral, with greenhouse gas reductions driving the LCFS, rather than other preferences for one technology or another. B4-26 cont.

III. THE BOARD'S GOVERNMENT CODE AND RELATED OBLIGATIONS

A. Analysis of Alternatives under the Government Code

Although the Legislature provides California administrative agencies discretion in achieving the purposes of the statutes it enacts, it also requires that agencies avoid unnecessary or unduly burdensome regulation. Agencies therefore may not propose regulations unless they have determined that no alternative to their own proposal would be "as effective and less burdensome to affected private persons and equally effective in implementing the statutory purpose or other provision of law." (Govt. Code, § 11346.5, subd. (a)(13).) Nor can an agency finally adopt its own proposal unless it can properly affirm and explain, with "supporting information," that "no alternative" it has considered "would be more effective and less burdensome to affected private persons than the adopted regulation, or would be more cost effective to affected private persons and equally effective" in meeting the proposal's legislative objective. (*Id.*, § 11346.9, subd. (a)(4).)

There is no question that the Proposed Amendments will affect "private persons." CARB staff estimates the Proposed Amendments would cause consumer fuels prices to rise significantly (up to \$0.36/gallon for gasoline and up to \$0.44/gallon for diesel), (ISOR, Appx. E at 50); a loss of over 25,000 jobs, (*id* at 63); and a 0.1% decline in the GDP. (*Id.* at 68.) As such, there is a burden of demonstrating that no alternative to the Proposed Amendments would be "as effective and less burdensome to affected private persons and equally effective in implementing the statutory purpose or other provision of law." (Govt. Code, § 11346.5, subd. (a)(13).) And before CARB may consider whether to take action on the Proposed Amendments, it would be B4-27

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necessary to demonstrate, with "supporting information," that "no alternative" that the Board has considered "would be more effective and less burdensome to affected private persons than the adopted regulation, or would be more cost effective to affected private persons and equally effective" in meeting the proposal's legislative objective. (*Id.*, § 11346.9, subd. (a)(4).) B4-27 cont.

CARB's Government Code alternatives analysis, located pages IX-1–IX-3 of the ISOR, does not substantially discharge CARB's duties under Sections 11346.5 and 11346.9. This section of the ISOR does not itself articulate the "statutory purpose" of the LCFS regulation, or evaluate each alternative against the statutory purpose. For this reason alone, the alternatives analysis is not adequate as an informational document, and does not include the analysis required under Sections 11346.5 and 11346.9. To find the "statutory purpose" of the LCFS, it is necessary to look outside the ISOR and to the text of SB 32. (See ISOR at EX-1, EX-2.) SB 32 states that: B4-28

> [i]n adopting rules and regulations to achieve the maximum technologically feasible and cost-effective greenhouse gas emissions reductions authorized by this division, the state board shall ensure that statewide greenhouse gas emissions are reduced to at least 40 percent below the statewide greenhouse gas emissions limit no later than December 31, 2030.

(Health & Saf. Code, § 38566.) Thus, the "statutory purpose" behind the LCFS regulation is to ensure GHG emissions will be "reduced to at least 40 percent below the statewide greenhouse gas emissions limit no later than December 31, 2030," in a manner that is technologically feasible and cost-effective. (*Id.*) The discussion of alternatives likewise falls short of statutory requirements.

The WSPA Alternative. WSPA submitted a proposed alternative in response to CARB's solicitation of alternatives. The WSPA Alternative contemplates that GHG emissions currently attributable to the LCFS program would "instead be achieved by the Assembly Bill (AB) 32 Cap B4-29 and Trade program in the most cost-effective manner to address GHG emissions." (EA at 207; see also ISOR at IX-1.) This proposal would be "paired with incentives to foster innovation." (ISOR at IX-1.) The ISOR, however, rejected this alternative, and declined to further analyze it, "because it is less likely to accomplish the innovation and fuel substituting benefits intended by the LCFS," (ISOR at IX-1–IX-2), and because CARB had not "been appropriated funding for such incentives." (*Id.* at IX-2.) The WSPA Alternative would also minimize leakage by avoiding "fuel shuffling." (See *supra,* § IV. B. 3.) By failing to consider the WSPA Alternative, the ISOR does not comply with the Government Code. First, the issue under Section 11346.5(a)(13) is not whether a proposed alternative meets each and every project objective articulated by an agency for a regulation. Rather, Section 11346.5(a)(13) requires CARB to evaluate whether the alternative would be "equally effective in implementing the statutory purpose . . . ." Here, the statutory purpose is ***not*** fostering innovation in fuel, (*cf.* ISOR at IX-2), but rather ensuring GHG emissions will be "reduced to at least 40 percent below the statewide greenhouse gas emissions limit no later than December 31, 2030," in a manner that is technologically feasible and cost-effective. (Health & Saf. Code, § 38566.) As such, "innovation" cannot be a proper basis to reject an alternative under Section 11346.5(a)(13). B4-29 cont.

In any event, the WSPA Alternative will spur innovation. Indeed, WSPA's strategy to use financial incentives to promote innovation is the same strategy that CARB itself has used to achieve the same goals. (Appendix A, Attachment 2.)

The WSPA Alternative would also be effective in achieving reduced emissions required under SB 32. As previously recognized by CARB when Growth Energy proposed a similar alternative in 2015, a cap-and-trade alternative would "likely" achieve the same "estimated GHG emissions reductions" as the LCFS regulation during the relevant period. (2015 ISOR (LCFS),

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Appx. F at 26-27.) There is no evidence or analysis to suggest that the WSPA Alternative would not be equally efficacious. It should also be noted that a demonstration that there are no superior alternatives to a proposed regulation, as required under Section 11346.9(a)(4), must be based on "supporting information." To date, however, there is no such "supporting information" in the rulemaking file of which Growth Energy is aware. If the Board intends to add such information to the rulemaking file in order to try to carry its burden under Section 11346.9(a)(4), it must comply with section 11347.1 of the Government Code. B4-29 cont.

The E15 Alternative. CARB should also consider an alternative under which CARB would concurrently adopt fuel specifications for E15, and incorporate E15 into the LCFS. This alternative would be more than "equally effective in implementing the statutory purpose," (Govt. Code, § 11346.5, subd. (a)(13)), of reducing greenhouse gas emissions "to at least 40 percent below the statewide greenhouse gas emissions limit no later than December 31, 2030," in a manner that is technologically feasible and cost-effective. (Health & Saf. Code, § 38566.)

Specifically, ethanol is a low CI fuel, and using greater percentage of ethanol would thus help reduce greenhouse gas emissions further. Moreover, the incorporation of E15 would be cost-effective because it would allow "greater use of low CI ethanol, [which] will result in the generation of greater volumes of credits under the LCFS program helping to ensure and further reduce the cost of LCFS compliance." (Appendix A, Attachment 3.) Further, because E15 is already being produced and is actively being used in at least 28 states, E15 is both "technologically feasible," (*id.*), and would help avoid the "significant and unavoidable" impacts identified in the EA resulting from the construction and/or modification of new facilities. As a result of the foregoing, CARB should not on the current record proceed to a final action because it cannot, among other things, comply with Section 11346.9(a)(4) of the Government Code. If B4-30 the Board intends to pursue the Executive Officer's proposal, the record must demonstrate that it has addressed the issues raised here, both substantive and procedural.[9]

B4-30 continued from previous page, continues to footnote below

B. Adequacy of the Economic Analysis in the SRIA

Under the APA, state agencies proposing to "adopt, amend, or repeal any administrative regulation" must first perform an assessment of "the potential for adverse economic impact on California business enterprises and individuals." (Govt. Code, § 11346.3, subd. (a).) Among other things, the APA requires that agencies such as CARB prepare a Standardized Regulatory Impact Assessment ("SRIA") analyzing "the potential adverse economic impact on California business and individuals of a proposed regulation," (Govt. Code, § 11346.3), and declare in the notice of proposed action any initial determination that the action will not have a significant statewide adverse economic impact directly affecting business. (Govt. Code, § 11346.5, subd. (a)(8); *WSPA*, *supra*, 57 Cal.4th at 428.) The APA requires the SRIA to evaluate several issues, including "elimination of jobs within the state," "the elimination of existing businesses within the state," and "[t]he competitive . . . disadvantages for businesses currently doing business within the state." (Govt. Code, § 11346.3, subds. (c)(1)(A)-(C).) The SRIA must be circulated with the 45-day materials (here, the ISOR), and must be supported by "facts, evidence, documents, [or] testimony," and made available for public review and comment for at least 45-days before an agency approves a regulation. (Govt. Code, §§ 11346.5, subds. (a)(7), (a)(8), 11347.3(b)(4).) The SRIA cannot be based on "mere speculati[on]." (*WSPA*, *supra*, 57 Cal.4th at 428.) "A regulation . . . may be declared invalid if . . . [t]he agency declaration . . . is in conflict with substantial evidence in the record." (*Calif. Ass'n of Medical Products Suppliers v. Maxwell-Jolly* (2011) 199 Cal.App.4th 286, 306.)

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[9] If the Board does not agree with Growth Energy's analysis of the obligations of section 11346.9(a)(4), Growth Energy requests that the Board explain its reasons for disagreement.

B4-30 continued from above

The current SRIA for the Proposed Amendments does not meet the applicable standards. The analysis of the LCFS regulation's "potential adverse economic impact on California business and individuals of a proposed regulation," (Govt. Code, § 11346.3), is contained on pages 69-70 of Appendix E to the ISOR.

The ISOR's discussion of the "the elimination of existing businesses within the state," and "[t]he competitive . . . disadvantages for businesses currently doing business within the state," (Govt. Code, § 11346.3, subds. (c)(1)(B)-(C)), does not fully address and take into account the ISOR's estimate that the LCFS regulation is projected to increase the price of gasoline up to \$0.36/gallon and diesel by up to \$0.44/gallon as early as 2025. (ISOR, Appx. E at 50.) The projected increase in the price of gasoline, which is directly attributable to the fact that the costs of the LCFS regulation are expected to be passed on to California consumers and businesses, is three-times higher than the controversial \$0.12/gallon tax increase recently approved by the Legislature in 2017. (See SB 1: The Road Repair and Accountability Act of 2017.) In addition, the SRIA estimates that the LCFS regulation could result in a loss of over 25,000 jobs, (*id* at 63), and a 0.1% decline in the GDP. (*Id.* at 68.) B4-31 cont.

Although impacts of this nature would dramatically affect small businesses,[10] the SRIA does not consider whether the increase in the price of gasoline or diesel could result in "the

[10] Various entities have expressed concern about the impact of the \$0.12/gallon increase on small businesses and families, many of which are summarizes in the following documents:

- *http://www.next10.org/sites/default/files/transportation-funding-brief-final.pdf*
- *http://www.nfib.com/content/news/california/small-business-reacts-to-passage-of-senate-bill-1/*
- *https://www.nfib.com/content/analysis/california/senate-bill-1-will-hurt-small-businesses-and-working-families/*
- *http://www.sacbee.com/news/politics-government/capitol-alert/article191161034.html*

elimination of existing businesses within the state . . . ." (Govt. Code, § 11346.3, subd. (c)(1)(B); *cf.* ISOR, Appx. E at 70.)

The SRIA's discussion of "[t]he competitive . . . disadvantages for businesses currently doing business within the state," (Govt. Code, § 11346.3, subd. (c)(1)(C)), also requires augmentation. While the SRIA does recognize that "California sectors that rely heavily on transportation fuel may face higher prices, resulting in a competitive disadvantage relative to out of state entities that are not subject to the LCFS," the SRIA makes no attempt to quantify the extent of the competitive disadvantage a $0.36/gallon increase in gas prices or a $0.46/gallon increase in the price of diesel fuel would create.

The SRIA relies on the suggestion that other jurisdictions will adopt their own versions of the LCFS regulation. The SRIA states that "due to the 2015 Paris Agreement reached by the Conference of Parties in Paris, which is aimed at keeping the global temperature rise below 2°C, staff expects signatories (which include all of the U.S.'s trading partners) to take action to reduce GHG emissions." (ISOR, Appx. E at 69.) This assertion, however, is not supported by any "facts, evidence, documents, [or] testimony" to suggest the adoption of LCFS-like regulations by other jurisdictions would decrease the price of fuels, or otherwise reduce competitive harm to "businesses currently doing business within the state . . . ." (Govt. Code, § 11346.3, subd. (c)(1)(C).) Further, there is no evidence that a critical mass of states have actually adopted regulations similar to the LCFS, nor are there statutes like AB 32 in other states that might be used to try to justify programs in addition to the RFS program. The only state to which the ISOR B4-31 cont.

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- *http://www.latimes.com/politics/la-pol-ca-gas-tax-repeal-20171229-story.html* points to adopting an LCFS regulation is Oregon, and at least one other state has declined to adopt an LCFS program like the one in California.[11] B4-31 continued from previous page, continues to footnote below

C. External Peer Review

The Health & Safety Code provides that CARB shall not "take any action to adopt the final version of a rule unless" it undertakes a peer review to evaluate the "scientific portions" of the rule. (Health & Saf. Code, § 57004(d).) Section 57004 requires that: (1) CARB "submit[] the scientific portions of the proposed rule, along with a statement of the scientific findings, conclusions, and assumptions on which the scientific portions of the proposed rule are based and the supporting scientific data, studies, and other appropriate materials, to the external scientific peer review entity for its evaluation," and (2) the peer reviewer "prepare[] a written report that contains an evaluation of the scientific basis of the proposed rule." (*Id.*, subd. (d).) Section 57004 of the Health and Safety Code defines the "scientific portions" of a proposed rule to include "those foundations of a rule that are premised upon, or derived from, empirical data or other scientific findings, conclusions, or assumptions establishing a regulatory level, standard, or other requirement for the protection of public health or the environment." (*Id.*, subd. (a)(2).) B4-32

Numerous aspects of the proposed amendments "are premised upon, or derived from, empirical data or other scientific findings, conclusions, or assumptions establishing a regulatory level, standard, or other requirement for the protection of public health or the environment." (*Id.*, subd. (a)(2).) These "scientific portions" include, but are not limited to:

- The accuracy of each of the components of CA-GREET 3.0, and the effect on the CI for corn ethanol and sugarcane ethanol;
- The ILUC for corn ethanol;

11 http://www.biofuelsdigest.com/bdigest/2015/07/03/washington-state-nixes-low-carbon-fuel-standard-via-transport-bill-poison-pill/ B4-31 continued from above

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- The EER for electricity;
- The efficacy of NTDEs to reduce NOx emissions from biodiesel;
- The accuracy of CARB's compliance scenario, including but not limited to the adaptation of alternative jet fuels, solar steam projects, and renewable diesel; and
- The potential impacts associated with CARB's compliance scenarios not coming to fruition, particularly with respect to alternative jet fuels, solar steam projects, and renewable diesel.

It is unclear whether CARB has sought external peer review to evaluate the scientific portions of the rule, consistent with Section 57004. As such, the subject of any such peer review is unknown. If CARB has not sought peer review under Section 57004, Growth Energy requests an explanation of the reason why none was sought and completed.

B4-32 cont.

D. The Proposed Amendments Are Not Consistent with AB 32

The Proposed Amendments are an "implementation measure" that would be adopted under color of AB 32. When the Legislature adopted AB 32, it wanted to ensure that criteria pollutants – such as NOx – would not increase. (Health & Saf. Code, § 38501.) As a result, AB 32 makes clear that any "market-based compliance mechanism" by CARB – such as the LCFS regulation – must be designed "to prevent any increase in the emissions of . . . criteria air pollutants." (Health & Saf., § 38570(b)(2).) Likewise, CARB must "[e]nsure" that any such activity does "not interfere with[] efforts to achieve and maintain federal and state ambient air quality standards . . . ." (Health & Saf., § 38562(b)(4).) In addition, implementation measures must "minimize leakage," defined as "a reduction of emissions of greenhouse gases within the

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state that is offset by an increase of emissions of greenhouse gases outside the state." (Health & Saf. Code, § 38562, subd. (b)(8); *id.*, § 38505, subd. (j).)

The LCFS regulation and the Proposed Amendments do not comply with AB 32 for several reasons:

- Using an accurate 2007 baseline, the LCFS regulation has resulted in increased and unmitigated NOx emissions from biodiesel since its inception. While ISOR Appendix G suggests these emissions would be mitigated through the payment of funds to local air districts for NOx mitigation projects, there is nothing in the Proposed Amendments that requires this to occur, and there is no analysis showing (i) where, (ii) in what amounts, (iii) for what specific purpose such funds would be spent, and (iv) how they will be funded. (See Appendix A, Attachment 4.) B4-33
- Substantial evidence suggests NOx emissions associated with biodiesel will increase in the future. The proposed mitigation to continuing NOx emissions is not consistent with CEQA, and the ISOR's conclusions are based on assumptions concerning industry's use of renewable diesel and alternative jet fuel, and the development of solar steam projects, none of which are required to occur, and all of which are speculative. (See Appendix A, Attachment 4.)
- The LCFS regulation will result in the construction of new or modified facilities for alternative fuels incentivized by the regulation. This will lead to increased criteria pollutant emissions, which CARB states are "significant and unavoidable." (See Appendix A, Attachment 4.)

- The LCFS regulation will continue to result in fuel shuffling, which increases emissions. (See Appendix C.)

It has been suggested the Proposed Amendments will "not interfere with[] efforts to achieve and maintain federal and state ambient air quality standards," (Health & Saf., § 38562(b)(4); see also *id.* § 38570(b)(2)), because the LCFS regulation is an "early action" under AB 32. (*Cf.* Health & Saf. Code, § 38560.5.) Specifically, pursuant to Section 38570.5(d) of the Health & Safety Code, "early action" measures were required to be "enforceable no later than January 1, 2010." The Proposed Amendments, however, will not be enforceable until after 2018. As such, Section 38570.5 does not apply to the Proposed Amendments. B4-33 cont.

Even if the Proposed Amendments to the LCFS regulation could be considered an "early action" measure, there is nothing in Section 38560.5 that exempts "early action" measures from the requirements of Section 38652. Prior rulemaking documents characterize Section 38562 as applying to "early action" measures, such as the LCFS. In the 2009 rulemaking, for example, the ISOR analyzed whether the LCFS regulation conformed to Section 38562's requirements, (2009 ISOR at ES-32–ES-34), including whether the LCFS regulation increased criteria pollutant emissions. (2009 ISOR at ES-33; see also 2009 ISOR at VII-35 [applying Section 38562]; see also 2015 FSOR at 974.)

E. Requirements of Transparency

Section 11347.3 of the Government Code requires CARB to maintain a "file of [the] rulemaking proceeding" for any proposed regulatory action subject to the APA, including the LCFS regulation. The rulemaking file must include, *inter alia*:

> (6) All data and other factual information, any studies or reports, and written comments submitted to the agency in connection with the adoption, amendment, or repeal of the regulation.

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> (7) All data and other factual information, technical, theoretical, and empirical studies or reports, if any, on which the agency is relying in the adoption, amendment, or repeal of a regulation, including any cost impact estimates as required by Section 11346.3.

(Govt. Code, § 11347.3, subds. (b)(5), (b)(6).) The rulemaking file must also include an index to the rulemaking that identifies each item contained in the file. (*Id.*, subd. (b)(12).)

The entire rulemaking file, including the foregoing material, must be "available to the public for inspection" from the time when the first notice of the proposed rulemaking is published in the California Regulatory Notice Register, (*id.*, subd. (a)), which occurred in this proceeding on March 9, 2018. (See Govt. Code, § 11346.3, subd. (a); see also *Administrative Rulemaking* (1999) 29 Cal. Law Rev. Comm'n Rep. 459, 469 [making the rulemaking file available upon the publication of the notice of the proposed rulemaking promotes meaningful public participation in the rulemaking process].)

As Section 11347.3(b) makes clear, rulemakings at CARB must include the creation of a rulemaking file that includes "***[a]ll*** data and other factual information, any studies or reports, and written comments submitted to the agency" in connection with the proposal. (Govt. Code, § 11347.3, subds. (a), (b)(6) [emphasis added].) To assure immediate public access to the supporting materials as soon as the 45-day materials are released, the APA requires that the 45-day notice include a statement that the agency on the date of the notice "has available ***all*** information upon which [the] proposal is based." (*Id.*, § 11346.5, subds. (a)(16) [emphasis added].) A separate provision confirms the agency must in fact make those records, and any other "public records, including reports, documentation, and other materials, related to the proposed action," available. (*Id.*, § 11346.5, subd. (b).)

The "written comments" that must be placed in the record are not simply those submitted to the agency in a particular manner or at a particular time, such as during the period between publication of the notice of a public hearing and public hearing – an agency must put "all" it receives "in connection with" a regulatory proposal in the rulemaking file. The Legislature's choice of words to describe what comments must be placed in the file – "in connection with" – sweep with intentional breadth, and require inclusion of any comments that bear on the subject of the regulatory effort. In addition, the period of public availability must "[c]ommenc[e] ***no later than*** the date that the notice of the proposed action is published." (*Id.*, § 11347.3, subd. (a) [emphasis added].) The use of the term "no later than" makes it clear that the Legislature expects written comments submitted in connection with a proposed regulatory action and received before publication of the required notice to be included in the rulemaking file.

Growth Energy has substantial concerns about the completeness of the rulemaking file for the proposed amendments, as it did in the prior rulemakings. The Court of Appeal made clear in *POET v. CARB* that neglect to include even a limited number of relevant documents in the rulemaking file would violate the Government Code.

As such, Growth Energy urges CARB to maintain a full and complete rulemaking file, and to make that file available for public review. Among other things:

B4-34

- The rulemaking file must include external communications submitted to the staff, the Executive Officer or the Board prior to the date when the rulemaking file is formally opened must be included in the rulemaking file. If those communications are not included, it should explained why.
- Growth Energy urges CARB to take all necessary measures to ensure all external submittals (not within the scope of section 11347.3(b)(7)) concerning this regulatory process have been included in the rulemaking file.

- Growth Energy also urges CARB to ensure all factual information relied upon by CARB staff in connection with the consideration of the Proposed Amendments is included in the rulemaking file. B4-34 cont.

IV. ENVIRONMENTAL ANALYSIS

A. CARB's Certified Regulatory Program

B4-35

CEQA requires that public agencies, such as CARB, "refrain from approving projects with significant environmental effects if there are feasible alternatives or mitigation measures that can substantially lessen or avoid those effects." (*City of Arcadia*, *supra*, 135 Cal.App.4th at 1421 [citing *Mountain Lion Found. v. Fish & Game Comm.* (1997) 16 Cal.4th 105, 134].) To perform this evaluation, "CEQA compels government first to identify the environmental effects of projects, and then to mitigate [any] adverse effects through the imposition of feasible mitigation measures or through the selection of feasible alternatives." (*Sierra Club*, *supra*, 7 Cal.4th at 1233.) "The CEQA process is intended to be a careful examination, fully open to the public, of the environmental consequences of a given project, covering the entire project, from start to finish. This examination is intended to provide the fullest information reasonably available upon which the decision makers and the public they serve can rely in determining whether or not to start the project at all, not merely to decide whether to finish it." (*NRDC v. City of Los Angeles* (2002) 103 Cal.App.4th 268, 271.)

State regulatory programs, such as CARB's, "that meet certain environmental standards and are certified by the Secretary of the California Resources Agency are exempt from CEQA's requirements for preparation of EIRs, negative declarations, and initial studies." (*City of Arcadia*, *supra*, 135 Cal.App.4th at 1421.) The scope of this exemption, however, is narrow, and only excuses a certified regulatory agency from complying with the requirements found in

Chapters 3 and 4 of CEQA (*i.e.*, Pub. Res. Code, §§ 21100-21154) in addition to Public Resources Code § 21167. (Pub. Res. Code, § 21080.5(c).) However, "[w]hen conducting its environmental review and preparing its documentation, a certified regulatory program is subject to the broad policy goals and substantive standards of CEQA." (Kostka & Zischke, *Practice Under Cal. Env. Quality Act* (2016 update) § 21.10] ["Kostka & Zischke"] [citing *City of Arcadia*, *supra*, 135 Cal.App.4th at 1422; *Sierra Club, supra,* 7 Cal.4th 1215; *Californians for Native Salmon & Steelhead Ass'n v. Dept. of Forestry* (1990) 221 Cal.App.3d 1419; *Envt'l Protection Info. Ctr. v. Johnson* (1985) 170 Cal.App.3d 604, 616].) The CEQA Guidelines implementing section 21080.5 provide that, "[i]n a certified program, an environmental document used as a substitute for an EIR must include '[a]lternatives to the activity and mitigation measures to avoid or reduce any significant or potentially significant effects that the project might have on the environment.'" (*City of Arcadia*, *supra*, 135 Cal.App.4th at 1422 [quoting CEQA Guidelines, § 15252(a)(2)(A)].) B4-35 cont.

CARB's functional equivalent document is the "staff report," which "shall be prepared and published by the staff of the state board." (17 Cal. Code Regs., § 60005(a).) The regulations require the staff report to be "published at least 45 days before the date of the public hearing" on the rulemaking, and to "be available for public review and comment." (*Id.*) Staff reports must be prepared "in a manner consistent" "with the goals and policies of" CEQA, and "shall contain":

> a description of the proposed action, an assessment of anticipated significant long or short term adverse and beneficial environmental impacts associated with the proposed action and a succinct analysis of those impacts. The analysis shall address feasible mitigation measures and feasible alternatives . . . which would substantially reduce any significant adverse impact identified.

(17 Cal. Code Regs., § 60005(b).)

The regulations also provide that an action "for which significant adverse environmental impacts have been identified during the review process shall ***not*** be approved or adopted as proposed if there are feasible mitigation measures or feasible alternatives available which would substantially reduce such adverse impact." (*Id.*, § 60006 [emphasis added].) "Feasible" means "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors, and consistent with the state board's legislatively mandated responsibilities and duties." (*Id.*)

If CARB receives comments raising "significant environmental issues associated with the proposed action," staff must "summarize and respond to the comments either orally or in a supplemental written report. Before taking final action on any proposal for which significant environmental issues have been raised, the decision maker shall approve a written response to each such issue." (*Id.*, § 60007.) CARB must respond to the issues raised by the public by providing a "good faith, reasoned analysis in response, and at a level of detail that matches the level of detail in the comment." (CEQA Guidelines, § 15088(c); *Pfeiffer v. City of Sunnyvale* (2011) 200 Cal.App.4th 1552, 1568.) If CARB disagrees with the "recommendations and objections raised in the comments," the "recommendations and objections" "must be addressed in detail," with the agency "giving reasons why specific comments and suggestions were not accepted." (CEQA Guidelines, § 15088(d).) "Conclusory statements unsupported by factual information will not suffice." (*Id.*) B4-35 cont.

CARB may not take "final action on any proposal which raise significant environmental issues associated with the proposed action" until the state board "approve[s] a written response to each" issue raised. (Cal. Code Regs., § 60007(a).) As such, CARB staff's responses to

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environmental comments must be presented to the state board before consideration of the Proposed Amendments for approval. (*Id.*) B4-35 cont.

B. Compliance with CEQA and CARB's Certified Regulatory Program

1. Analysis of NOx Emissions Associated with Biodiesel

The Causal Connection between the LCFS Regulation and Increased NOx Emissions.

B4-36

In its decision in *POET I,* the Court of Appeal found CARB did not adequately consider potential NOx emissions from biodiesel incented by the LCFS regulation. The Court thus directed CARB to:

> Address whether the project will have a significant adverse effect on the environment as a result of increased NOx emissions, make findings (supported by substantial evidence) regarding the potential adverse environmental effect of increased NOx emissions, and adopt mitigation measures in the event the environmental effects are found to be significant.

(*POET I, supra*, 218 Cal.App.4th at 767.) Thereafter, the Superior Court issued a Peremptory Writ in February 2014 that included the following language in Paragraph 3:

> ARB shall address whether the project will have a significant adverse effect on the environment as a result of increased NOx emissions, make findings (supported by substantial evidence) regarding the potential adverse environmental effect of increased NOx emissions, and adopt mitigation measures in the event the environmental effects are found to be significant.

(February 10, 2014, Peremptory Writ of Mandate ¶ 3, *POET, LLC v. CARB*, Fresno County Superior Court, Case No. 09 CE CG 04659.)

CARB attempted to take corrective action to address Paragraph 3 in its 2014-15 rulemaking that sought to modify and readopt the LCFS regulation. The Court of Appeal, however, found CARB did not adequately address the NOx emissions caused by the LCFS regulation in effect in 2014; rather, the Court found that CARB made a comparison of emissions "between (1) an estimate of the emissions of all diesel fuel and its substitutes used in 2014 and

(2) a hypothetical emissions profile that would have been generated if conventional diesel had replaced all of the biodiesel and renewable diesel fuel used in 2014." (*POET, LLC v. California Air Resources Board* (2017) 12 Cal.App.5th 52, 68 ["*POET II*"].) By engaging in this method of analysis, the Court found CARB did not adequately assess the impacts of the original LCFS regulation on the environment.

The Fifth District found CARB erred by proceeding in this fashion. (*Id.* at 100.) The Court found the original LCFS regulation adopted in 2009 and the LCFS regulation readopted by CARB in 2015 were the same "project" under CEQA. (*Id.* at 75.) The Fifth District also found CARB's use of a 2014 baseline was error because that baseline did "not describe the conditions existing when the environmental analysis of the project commenced," (*id.* at 80), and that CARB instead should have identified "the conditions that existed before any impacts of the original LCFS regulations began to accrue and, thus, would provide a solid foundation for identifying those impacts." (*Id.* at 81.) Appendix G to the ISOR appears to be the document prepared to address the ruling in *POET II*. Appendix G states, *inter alia*, that it considers "biodiesel NOx emissions for the entire history of LCFS regulations to date," (ISOR, Appx. G at G-2), using a 2007 baseline. Appendix G also states CARB has developed "remediation measures CARB proposes to take to address" both past NOx emissions attributable to the LCFS, as well as forward-looking mitigation measures. (*Id.*)

B4-36 cont.

Growth Energy has several concerns with the analysis and mitigation identified in Appendix G. As an initial matter, the ISOR continues to underestimate the amount of NOx caused by biodiesel emissions allowed by the LCFS regulation based on the ISOR's analysis regarding incentives under the federal Renewable Fuels Standard ("RFS"). In addition, the mitigation measures proposed by CARB for past and future NOx emissions do not contain all of the components required under CEQA. The ISOR's proposal to provide "backward-looking" mitigation for past NOx emissions impermissibly defers mitigation, and does not ensure the proposed mitigation will actually occur. The mitigation identified to reduce future NOx emissions likewise does not comport with CEQA's standards. For example, the adoption of New Technology Diesel Engines ("NTDE") engines is not based on a legally binding requirement. Moreover, while the ISOR relies upon assumptions regarding renewable diesel displacing biodiesel in sufficient quantities to effectuate a net benefit as to NOx emissions, there is no legally binding mechanism to ensure renewable diesels will be used in such quantities, nor are there any additional measures identified and imposed upon CARB in the event the ISOR's projections regarding renewable diesel never come to pass. B4-36 cont.

The Role of the RFS Regulation on Biodiesel Use in California. According to the ISOR, "Congress and the United States Environmental Protection Agency (U.S. EPA) have strongly encouraged, and even required, the use of progressively increasing volumes of [biodiesel and renewable diesel] fuels since 2009." (ISOR, Appx. G at G-10.) In Section C of Appendix G, the ISOR attempts to differentiate between biodiesel usage incentivized by the LCFS regulation, and biodiesel usage attributed to other incentives, such as federal regulations. B4-37

This analysis is based on the incorrect suggestion that CARB was powerless, in either the original LCFS regulation or subsequent regulations, to address NOx emissions from biodiesel incentivized by federal programs. The ISOR's analysis also presumes that wide-scale biodiesel usage in California would have been permissible without action by CARB. Neither assumption is supported by the evidence, as CARB wielded considerable authority as a gatekeeper, regardless of any federal incentives. Among other things, CARB must perform a multimedia

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evaluation under Section 43830.8 of the Health & Safety Code for certain new fuels, including biodiesel.

In addition, armed with its contemporaneous understanding in 2009 (and earlier) that increased biodiesel usage would result in increased NOx emissions, (2009 ISOR at VII-19), and that the federal RFS would incentivize biodiesel in California, CARB could have taken any number of actions within the LCFS to address increased NOx from biodiesel usage:

- CARB could have adopted mitigation to avoid increases in NOx emissions from biodiesel. For example, CARB could have adopted a version of the ADF regulation in 2009 to help ensure legally enforceable mitigation existed prior to the wide-scale introduction of biodiesel to California. B4-37 cont.
- CARB could have likewise prohibited wide-scale biodiesel usage in California until such mitigation was adopted.
- CARB could have declined to include biodiesel in the original LCFS regulation, removing the additional state-based incentives to any fuels allegedly being incented by federal regulations.

CARB, however, did not consider this issue in 2009. Instead, the Court of Appeal found CARB "sidestepped and never reached the question of whether any increase would constitute a 'significant effect on the environment." (*POET II*, *supra*, 12 Cal.App.5th at 64.) CARB also conducted the multimedia evaluation for biodiesel, and provided biodiesel a favorable CI value compared to traditional diesel fuel, further incentivizing its use. (See 2009 Final Regulation Order at 49.) In other words, even assuming, *arguendo*, some portion of increased NOx from biodiesel usage was attributable, in part, to federal incentives, the LCFS in fact exacerbated the issue by authorizing biodiesel usage without mitigation, and incorporating biodiesel into the program. (*Calif. Bldg. Industry Assn. v. Bay Area Air Quality Mgmt. Dist.* (2015) 62 Cal.4th 369, 388 ["CEQA calls upon an agency to evaluate existing conditions in order to assess whether a project could exacerbate hazards that are already present."]; *East Sacramento Partnership for a Livable City v. City of Sacramento* 5 Cal.App.5th 281, 296 ["What must be analyzed under CEQA is a project's potentially significant exacerbating effects on existing environmental hazards . . . ."] [internal quotations omitted]; *Visalia Retail, LP v. City of Visalia* (2018) 20 Cal.App.5th 1, 13 [stating that the requirement of CEQA review is triggered if a project "affects the physical environment . . . by causing or increasing" a significant impact]; *Joshua Tree Downtown Business Alliance v. County of Sen Bernardino* (2016) 1 Cal.App.5th 677, 685 [same].) B4-37 cont.

In addition, the attribution of most NOx emissions from biodiesel to the RFS is not supported by the facts. "[T]here is nothing in the ADF regulation, the LCFS regulation, or the proposed amendments . . . that mandates the use of any volume of biodiesel in California, much less the use of the exact ratio of renewable diesel to biodiesel assumed by [the ISOR] in its emissions analysis." (Appendix A, Attachment 4 at 5.) And even if the ISOR generates the anticipated volumes of renewable diesel, CARB "has already formally committed to taking credit for those NOx reductions as part of a "Low-Emission Diesel" requirement as of the agency's Mobile Source State Implementation Plan (SIP) Strategy." (*Id.*) As such, "those reductions cannot be claimed to offset potential NOx increases from the use of biodiesel resulting from the LCFS." (*Id.*)

And even if it could be argued that the LCFS is not responsible for some of the biodiesel usage in California, and that such usage was the sole responsibility of the RFS program, this does not mean the EA can avoid mitigation for such emissions. CEQA requires that CARB's functional equivalent environmental document discuss the cumulative effect on the environment of the subject project in conjunction with other closely-related ***past***, present, and reasonably foreseeable probable future projects. (See, e.g., Pub. Resources Code, § 21083, subd. (b).) "The purpose of this requirement is obvious: consideration of the effects of a project or projects as if no others existed would encourage the piecemeal approval of several projects that, taken together, could overwhelm the natural environment and disastrously overburden the man-made infrastructure and vital community services. This would effectively defeat CEQA's mandate to review the actual effect of the projects upon the environment." (*Citizens to Preserve the Ojai v. County of Ventura* (1985) 176 Cal.App.3d 421, 432.) Thus, even if it could be argued that increased past and future NOx emissions were caused ***solely*** by the RFS, those emissions must still be addressed, analyzed, and mitigated as cumulative impacts under CEQA. B4-37 cont.

The Adequacy of Mitigation Measures Identified for Past NOx Emissions from Biodiesel. Appendix G proposes mitigation for historic NOx emissions that the ISOR attributes to the LCFS regulation (which, as explained above, are understated). To mitigate for these emissions, the ISOR states "CARB will offset historical potential LCFS-attributed biomass-based diesel NOx emissions through a remedial measure that funds air district-level NOx mitigation projects targeting engines, such as the replacement of existing diesel engines with low-NOx engines." (ISOR, Appx. G at G-56.) Appendix G, in turn, states that CARB "cannot speculate as to the ultimate locations or specific projects selected for funding under this measure," but that the "remedial measure itself ***would be*** designed to result in beneficial environmental impacts" by reducing "NOx emissions in an amount sufficient to remediate historical potential LCFS-attributed biomass-based diesel NOx emissions." (*Id.* [emphasis added].) B4-38

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The ISOR states that, due to the alleged benefits of biodiesel to Particulate Matter ("PM") emissions, CARB could use this as an "overriding consideration[] related to potentially significant and unavoidable historical air quality impacts . . . ." (ISOR, Appx. G at G-57.) In *Mission Bay Alliance v. Office of Community Investment and Infrastructure* (2016) 6 Cal.App.5th 160, however, the court explained:

> Under CEQA, an agency may approve a project with significant, unavoidable environmental impacts if it adopts a statement of overriding considerations finding that particular economic, social, or other considerations make the alternatives and mitigation measures infeasible and that particular project benefits outweigh the adverse environmental effects . . . [but first] an agency must show that it has considered the mitigation measures and project alternatives identified in the EIR that would lessen the significant environmental effects.

B4-38 cont.

(*Id.* at 183–184.)

Moreover, the proposed mitigation is not sufficient under CEQA for several reasons. First, agencies usually cannot defer formulation of mitigation measures to some point in the future. (See CEQA Guidelines, § 15126.4(a)(1)(B); *POET I*, *supra*, 218 Cal.App.4th at 735.) As such, the ISOR's suggestion that this remedial measure "would be" designed at some point in the future to create "beneficial impacts" is inconsistent with CEQA.

In addition, the proposed mitigation measure for past NOx emissions is essentially a fee-based mitigation. A commitment to pay fees, however, is not adequate mitigation if there is no evidence the mitigation will actually result. (See *Calif. Clean Energy Comm. v. City of Woodland* (2014) 225 Cal.App.4th 173, 197; *Gray v. County of Madera* (2008) 167 Cal.App.4th 1099, 1122; *Kings County Farm Bureau v. City of Hanford* (1990) 221 Cal.App.3d 692, 727.) Here, the ISOR identifies no specific projects, and provides no explanation as to how the programs it references would actually result in a ton-for-ton mitigation of past NOx emissions. Nor is there anything in the record to show exactly which air districts would be the focus of these funding efforts, and that the selected districts would be located in the areas most affected by increases in NOx (*i.e.*, the San Joaquin Valley Air Pollution Control District or the South Coast Air Quality Management District). Likewise, there is no evidence as to how the mitigation would be funded.

The ISOR also contains no evidence to suggest CARB would be legally bound to provide any specific amount of funding as a condition of approving the Proposed Amendments. (See *Anderson First Coalition v. City of Anderson* (2005) 130 Cal.App.4th 1173, 1187; *Save Our Peninsula Comm. v. Monterey County Bd. of Supervisors* (2001) 87 Cal.App.4th 99, 141.) This is important because an agency must ensure a mitigation measure will actually be implemented. (*Federation of Hillside & Cyn. Ass'ns v. City of Los Angeles* (2000) 83 Cal.App.4th 1252, 1261.) B4-38 cont.

The Adequacy of Mitigation Identified to Reduce Future NOx Emissions from Biodiesel. To mitigate future NOx emissions from biodiesel, the ISOR generally relies on the in-use requirements under the current ADF regulation. Those in-use requirements, however, are currently subject to sunset provisions. As a result, CARB intends to expand the sunset provisions in the ADF regulation to incorporate NTDEs by off-road diesel vehicles:

1. The vehicle miles traveled (VMT) by NTDE heavy-duty on-road diesel vehicles in California reaches 90 percent of total VMT by the California heavy-duty on-road fleet, based on the most current CARB mobile source emissions inventory; and B4-39

2. The hours of operation of NTDE off-road diesel engines in California reaches 90 percent of total hours of operation by the California heavy-duty off-road diesel engine fleet (exclusive of OGVs),[] based on the most current CARB mobile source emissions inventory.

(ISOR, Appx. G at G-58.)

This mitigation is based upon the conclusion that NTDEs using biodiesel blends of B20 or less would result in ***no*** increase in NOx emissions. This conclusion, however, is not supported by the evidence. Specifically, the consensus within the scientific literature is that

NTDEs using biodiesel blends of B20 or less ***caused NOx emissions to increase***, and that such increases could total as much as 9.73 additional tons per day of NOx emissions statewide in 2020. (Appendix A, Attachment 4.) The only study it appears the ISOR has relied upon is the 2012 Lammert study (the "Lammert Study"). Although CARB in a prior ISOR recognized that Lammert was not consistent with other existing studies – all of which showed increased NOx emissions would result – the 2015 ISOR dismissed the remaining studies on the grounds that they were performed on "either retrofit engines or non-commercial engines . . . ." (2015 ISOR (ADF) at 44/87.) This position, however, is no longer relevant because CARB staff and CARB contractors have now published several studies – performed with testing on OEM production vehicles, and not retrofits – that biodiesel increases NOx emissions from NTDEs. (Appendix A, Attachment 4.) B4-39 cont.

As such, CARB cannot rely upon the use of NTDEs by industry as a mechanism to sunset the in-use biodiesel requirements under the LCFS.

The Role of Renewable Diesel in Mitigating/Offsetting NOx Emissions. One of the methods contemplated under the LCFS regulation and the ADF regulation to reduce NOx emissions from biodiesel is the increased use of renewable diesel. (See EA at 65.) This mitigation, however, is based upon the assumption that renewable diesel will gradually displace biodiesel as an alternative diesel. (See, e.g., EA at 65.) Thus, the efficacy of the mitigation contained in the ISOR to reduce NOx emissions is based upon assumptions about what industry "may" do as a "possible pathway" to comply with the LCFS regulation. Nothing ***requires*** industry to do anything to use renewable diesel at any particular level, or assures the public the alleged reductions in NOx will occur. B4-40

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CEQA, however, requires mitigation measures to be enforceable through means that are legally binding. (Pub. Resources Code, § 21081.6(b); CEQA Guidelines, § 15126.4.) This requirement is designed to ensure that mitigation measures will actually be implemented, not merely adopted and then ignored. (*Fed. of Hillside & Cyn*, *supra*, 83 Cal.App.4th at 1261; *Anderson First*, *supra*, 130 Cal.App.4th at 1186.) In addition to being legally enforceable, a lead agency must also demonstrate the identified mitigation measures would be effective in reducing the identified impact to a less than significant level. (*Gray*, *supra*, 167 Cal.App.4th at 1115.) While an agency is not precluded from adopting a mitigation measure that might not be effective in minimizing a significant effect, it must acknowledge the uncertainty and adopt a statement of overriding considerations. (*Citizens for Open Govt. v. City of Lodi* (2012) 205 Cal.App.4th 296, 322; *Fairview Neighbors v. County of Ventura* (1999) 70 Cal.App.4th 238, 242.) B4-40 cont.

Here, the conclusions in the ISOR that NOx emissions will decrease are based upon assumptions regarding the displacement of biodiesel by renewable diesel. These assumptions are insufficient to establish the ADF Regulation will result in "effective" or "enforceable" mitigation under CEQA.

In any event, the conclusion that the expected levels of renewable diesel usage would occur in sufficient volumes to offset NOx emissions from biodiesel is unsupported by the evidence. (Appendix A, Attachment 4.) But even if California experienced such levels of renewable diesel levels, "CARB has already formally committed to taking credit for those NOx reductions as part of a "Low-Emission Diesel" requirement as part of the agency's Mobile Source State Implementation Plan (SIP) Strategy." (*Id.*)

Accordingly, the ISOR cannot presume NOx emissions from biodiesel will be offset through greater use of renewable diesels.

Solar Steam Projects. The EA also suggests total NOx emissions associated with biodiesel would be reduced through decreases in NOx emissions from the implementation of solar steam projects at oil fields. (EA at 66.) Specifically, the ISOR projects a "decrease in both NOx and PM2.5 emissions due to" a "large reduction in emissions from natural gas-fired steam generators as solar steam projects are implemented," which would "primarily occur in the San Joaquin Valley air basin." (*Id.*)

The reference to solar steam projects is insufficient to serve as mitigation because the conclusion as to how industry will react to the LCFS regulation is merely based on "assumptions" in the compliance scenarios supporting the LCFS. There is nothing in the LCFS regulation actually requiring that solar steam projects will be built. As such, to the extent CARB seeks to rely upon solar steam projects to confirm there will be no increase in NOx emissions, such projects cannot be considered an effective mitigation measure under CEQA because they are not based upon an enforceable obligation, (Pub. Resources Code, § 21081.6(b); CEQA Guidelines, § 15126.4), and there is no assurance such projects will actually be implemented. (*Fed. of Hillside & Cyn. Ass'ns*, *supra*, 83 Cal.App.4th at 1261; *Anderson First*, *supra*, 130 Cal.App.4th at 1186.) There is likewise no assurance that a sufficient number of solar steam projects will be implemented to ensure they will result in a reduction of NOx emissions to a less than significant level. (*Gray*, *supra*, 167 Cal.App.4th at 1115.) Nor does the EA articulate any performance standards. B4-41

In addition, the conclusion that the benefits from solar steam projects would offset NOx emissions from biodiesel is unsupported by the evidence, as there is nothing in the LCFS that actually requires the completion of solar steam projects. (Appendix A, Attachment 4.)

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Accordingly, the ISOR cannot rely upon an assumption that the development of solar steam projects will offset NOx emissions from biodiesel. B4-41 cont.

Alterative Jet Fuel. The ISOR also posits that the "Proposed Amendments would result in an increased use of" Alternative Jet Fuel ("AJF") at California airports, and that "slight or negligible reductions in NOx relative to conventional jet fuel" would help offset NOx emissions from biodiesel. (EA at 63, 66-67.)

Using assumptions regarding industry's adaptation of AJF to offset NOx emissions from biodiesel does not serve as adequate mitigation. As with solar steam projects, a reliance on AJF cannot serve as mitigation because the conclusion as to how industry will react to the LCFS regulation is merely based on the assumptions in the LCFS compliance scenarios. The LCFS, however, does not require that AJF be used in any particular quantity. As a result, any offset for AJF use is not based upon an enforceable obligation, (Pub. Resources Code, § 21081.6(b); CEQA Guidelines, § 15126.4), and there is no assurance AJF will displace conventional jet fuels at any particular quantity or rate. (*Fed. of Hillside & Cyn. Ass'ns*, *supra*, 83 Cal.App.4th at 1261; *Anderson First*, *supra*, 130 Cal.App.4th at 1186.) There is likewise no assurance that AJF will displace conventional jet fuels at sufficient quantities to ensure that displacement will reduce NOx emissions associated with biodiesel usage to a less than significant level. (*Gray*, *supra*, 167 Cal.App.4th at 1115.) B4-42

Moreover, any assumption that AJF displacing conventional jet fuel would offset NOx emissions from biodiesel is unsupported by the evidence, since there is nothing in the LCFS that actually requires the use of AJF at any particular level. (Appendix A, Attachment 4.)

Thus, the ISOR cannot rely upon AJF as a method to offset increased NOx emissions from biodiesel.

2. Potential Impacts Associated with the Construction of New or Modified Facilities

The EA states that the Proposed Amendments would result in the construction of a large number of new and modified facilities needed to produce alternative fuels. For a wide range of resources, the EA finds the impacts of these new facilities to be significant. Although in several instances the EA identifies potential mitigation to offset these impacts, and notes that these measures could reduce the impacts to a less-than-significant level, the EA ultimately does not identify any mitigation measures that would provide enforceable mechanisms to lessen the significant impacts of the LCFS regulation – even though CARB enjoys the authority to approve new pathways under the LCFS for such facilities. Instead, for each of the resources, the EA finds the impact would continue to be significant and unavoidable because CARB does not possess land use authority over new facilities. B4-43

Before Finding the Impacts of a Project Are Significant and Unavoidable, an Agency must First Adequately Analyze the Issue. As an initial matter, an environmental document cannot simply label an impact "significant and unavoidable" without first providing a discussion and analysis. Such an approach "allows the agency to travel the legally impermissible easy road to CEQA compliance." (*Berkeley Keep Jets Over the Bay Comm. v. Bd. of Port Comm'rs* (2001) 91 Cal.App.4th 1344, 1370.) Rather, the lead agency must quantify the impact, and consider feasible mitigation based on that analysis. (See, e.g., *Sundstrom v. County of Mendocino* (1988) 202 Cal.App.3d 352, 311 ["CEQA places the burden of environmental investigation on government rather than the public," and a lead agency "should not be allowed to hide behind its own failure to gather data."].) B4-44

Any such analysis would not be speculative. By recognizing that the construction and modification of these facilities is a "reasonably foreseeable" consequence of the Proposed

Amendments by identifying the impact as a potentially significant effect of the project in the EA, the EA concedes CARB should analyze these impacts, at least at a general level. (CEQA Guidelines, § 15358 [lead agency must consider "[i]ndirect or secondary effects which are caused by the project and are later in time or farther removed in distance, but are still ***reasonably foreseeable***."] [emphasis added].) Moreover, the EA does not include the "same kind of health risk assessment of potential California biofuel facilities that was presented in the 2015 LCFS ISOR as part of" its analysis of air quality impacts in the 2018 EA. (Appendix A, Attachment 5.)

B4-44 cont.

B4-45

The Estimate of Impacts of New or Modified Facilities is Understated. In addition, the EA's estimate of potential impacts associated with the construction of new or modified facilities appear to be understated. In prior rulemakings, CARB has estimated that a single "Potential California Celluosic Ethanol Facility" in Northern California would have operational NOx emissions of 1,435 tons per year (an amount equal to approximately 3.9 tons per day). (See 2015 ISOR (LCFS) at IV-7.) This "is well in excess of any local California air quality district's threshold for a significant impact and would require extensive mitigation," and "is over 120 times greater than the NOx emission factor that CARB staff used for the 2018 LCFS analysis which is presented in Table F-3 of Appendix F to the 2018 ISOR." The current EA contains no explanation as to why NOx emissions from the facility described in the 2015 ISOR – which were estimated based on information "derived directly from data for a biomass plant as shown in Table IV-15 of the 2015 ISOR" – are not included in the analysis of such facilities in the current EA. (See Appendix A, Attachment 5.)

B4-46

Feasible Mitigation Exists to Lessen the Impacts of New or Modified Facilities. In its discussion of environmental impacts associated with new or modified facilities, the EA states mitigation is necessary, and in some sections appears to recommend mitigation to avoid the

B4-47

significant impacts of the Proposed Amendments. However, while the EA refers to specific mitigation measures, these discussions do not include any actual mitigation measures.

For instance, the section of the EA that concerns long-term operational air quality emissions includes a header that suggests the EA is identifying a specific mitigation measure – *i.e.*, "Mitigation Measure B.3.b" – to lessen such impacts. The EA, however, does not actually include any language suggesting what the text of that mitigation measure might be; rather, the discussion under the header "Mitigation Measure B.3.b" merely argues no mitigation is necessary. (See EA at 69-71.)

This renders the entire discussion somewhat confusing because it is unclear whether the EA is seeking to identify potential mitigation measures to reduce the impacts of the Proposed Amendments, and the LCFS regulation as a whole, or asserting no mitigation is necessary (which is not consistent with the title and format of the document). B4-47 cont.

In addition, although Appendix G references specific mitigation/remedial measures designed to lessen the potentially significant environmental impacts associated with NOx emissions from biodiesel, the air quality section of the EA does not itself identify any mitigation measures. In fact, the conclusion on pages 69-71 of the EA that no mitigation is available appears to be inconsistent with the identification of potential mitigation in Appendix G.

The same issues appear in most of the resource impact sections of the EA. (See, e.g., EA at 47 [aesthetics], 50 [agricultural and forest resources], 55 [air quality], 72 [biological resources], 77 [cultural resources], 80 [energy demand], 82 [geology and soils], 87 [greenhouse gas emissions], 89 [hazards and hazardous materials], 96 [hydrology and water quality], 101 [land use and planning], 104 [mineral resources], 107 [noise], 112 [population and housing], 113

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[public services], 114 [recreation and traffic], 115 [transportation and traffic], 120 [utilities and service systems].)

The analysis of these new facilities should be revised and augmented for several reasons. As an initial matter, CARB should consider reorganizing the EA and ensuring the conclusions stated therein are consistent to promote CEQA's basic informational and organizational requirements. In the related statutes that concern the preparation of environmental impact reports, CEQA makes plain that lead agencies are required to organize their environmental documents in a manner that will make them "meaningful and useful to decision-makers and to the public." (Pub. Resources Code, § 21003, subd. (b).) The data presented in the environmental document must adequately inform the public and the decision-makers. (*Vineyard Area Citizens for Responsible Growth v. City of Rancho Cordova* (2007) 40 Cal.4th 412, 442.) The environmental document may not be written is such a manner that forces readers "to sift through obscure minutiae or appendices" to find important components of the analysis. (See *San Joaquin Raptor Rescue Ctr. v. County of Merced* (2007) 149 Cal.App.4th 645, 659; see also *Calif. Oak Found. v. City of Santa Clarita* (2005) 133 Cal.App.4th 1219, 1239.) B4-47 cont.

In addition, having identified potential mitigation for the impacts of the LCFS regulation, CARB should attempt to find a way to make those measures enforceable. CARB's CEQA regulations provide that "[a]ny action or proposal for which significant adverse environmental impacts have been identified during the review process ***shall not be approved*** or adopted as proposed ***if there are feasible mitigation measures*** . . . available which would substantially reduce such adverse impact." (17 Cal. Code Regs., § 60006 [emphasis added].)

The EA states that "CARB does not have the authority to require implementation of mitigation related to operation of new or modified facilities that would be approved by local jurisdictions." (EA at 69.) While it may be technically true that CARB is not the local land use agency that would approve discretionary land use entitlements for new or modified facilities, this does not mean that CARB could not develop mitigation measures to lessen the impacts of any such future projects.[12] (See Appendix A, Attachment 5.)

For example, "in approving the fuel production pathway CI values for modified and new California facilities, CARB could modify the LCFS regulation to withhold approval unless all significant environmental impacts of a facility were adequately mitigated." In addition, CARB could require that "project proponents and operators engage in Voluntary Emission Reduction Agreements (VERAs) like those that are currently being required in the San Joaquin Valley," to ensure their emissions do not exceed a particular level.

Accordingly, the EA should be augmented to properly address the potentially significant impacts of the Proposed Amendments, and recirculated for public review.

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3. Fuel Shuffling

Although the LCFS regulation and the Proposed Amendments are intended to implement the Legislature's mandate in AB 32 to reduce greenhouse gas emissions in order to address the issue of global warming, CARB has admitted that the LCFS regulation would have "little or no" impact on CO_2 emissions:

> [F]uel producers are free to ship lower-carbon fuels to areas with [LCFS] standards, while shipping higher-carbon fuels elsewhere. The end result of this fuel 'shuffling' process is little or no net change in fuel carbon content on a global scale.

B4-48

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12 The EA relies upon assumptions regarding future solar steam projects and displacement of conventional jet fuel with AJF to offset emissions associated with NOx emissions from new or modified facilities. As explained above, however, the EA cannot rely upon these assumptions to offset NOx emissions from other sources. (See *supra*, § IV.B.1.)

B4-47 continued from above

(2009 ISOR at ES-27.) There is no environmental advantage to fuel shuffling, as the same fuels are still produced and consumed, and similar amounts of greenhouse gas are still emitted from those processes. Rather, because the LCFS regulation encourages the shipment of fuels to alternative locations that are further from origin facilities, fuel shuffling actually causes emissions of greenhouse gases to increase. Shuffling is a form of "leakage," which AB 32 requires CARB to avoid or minimize. (Health & Saf. Code, § 38562, subd. (b)(8).)

As explained in Appendix C, significant fuel shuffling is occurring at the domestic level. As Growth Energy previously predicted, shortly after the enactment of the LCFS regulation, domestic fuel providers began "rationalizing" or "shuffling" their shipments. Higher CI facilities ceased shipping to California, and instead redirected their fuel output entirely to other states. B4-48 cont. Conversely, lower CI facilities began increasing the volume of their shipments to California, resulting in a concentration of California deliveries in a limited number of low CI plants. These adjustments have continued to occur as the regulatory levels under the LCFS regulation continue to decrease, magnifying the effects of fuel shuffling.

Despite the extensive evidence of "fuel shuffling," neither the EA nor the ISOR discusses this important issue. There is no explanation in either the ISOR or the EA to suggest that fuel shuffling would not occur. Further, neither document attempts to ascertain the extent to which fuel shuffling is occurring, or seeks to quantify the increase in greenhouse gas emissions caused by the fuel shuffling. Adoption of the WSPA Alternative over the current LCFS program would, of course, avoid the leakage in greenhouse gas controls caused by the program; the ISOR and the EA do not address that important difference between the LCFS program and the WSPA Alternative.

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The EA likewise does not evaluate whether fuel shuffling caused by the Proposed Amendments would result in additional increases in criteria pollutant emissions. Because transportation of fuels by rail, truck, and sea indisputably create emissions of criteria pollutants, both inside and outside[13] California, the EA must analyze those potential impacts to determine whether they are significant. (See, e.g., *Sundstrom*, *supra*, 202 Cal.App.3d at 311 ["CEQA places the burden of environmental investigation on government rather than the public," and a lead agency "should not be allowed to hide behind its own failure to gather data."].)

B4-48 continued from previous page, continues to footnote below

Thus, to accurately identify and analyze the impacts of the Proposed Amendments, the EA must be revised to address impacts associated with fuel shuffling, and the EA should be recirculated for public review.

4. Analysis of Feasible Alternatives to the LCFS Regulation

The requirement that environmental documents identify and discuss alternatives to the project stems from the fundamental statutory policy that public agencies should require the implementation of feasible alternatives or mitigation measures to reduce the project's significant impacts. (See, e.g., Pub. Resources Code, § 21002.) The lead agency must focus on alternatives that can avoid or substantially lessen a project's significant environmental effects. (See *id.*) The CEQA Guidelines specifically recognize that comments raised by members of the public on an environmental document are particularly helpful if they suggest "additional specific alternatives . . . that would provide better ways to avoid or mitigate the significant environmental effects." (CEQA Guidelines, § 15204.)

B4-49

13 The EA analyze both in-state and out-of-state impacts caused by the Regulation. CEQA defines "environment" to include "the physical conditions that exist within the area which will be affected by a proposed project, including land, air, water, minerals, flora, fauna, noise, or objects of historic or aesthetic significance." (Public Resources Code, § 21060.5.) That definition includes no geographic limitation. We also understand CARB has considered out-of-state impacts in prior rulemakings.

B4-48 continued from above

The WSPA Alternative. Pursuant to Section 15126.6(c) of the CEQA Guidelines, the EA eliminates the WSPA Alternative from consideration. The alternative presented by WSPA contemplated that GHG emissions currently attributable to the LCFS program would "instead be achieved by the Assembly Bill (AB) 32 Cap and Trade program in the most cost-effective manner to address GHG emissions."[14] (EA at 207.)

The EA should not reject consideration of the WSPA Alternative, but should instead discuss the alternative and allow the Board to make the decision as to whether or not to approve the alternative instead of the Proposed Amendments. The WSPA Alternative would avoid most, if not all, of the significant impacts identified in the EA associated with the construction of new or expanded fuel production facilities in California. Because the WSPA Alternative would lessen the "significant and unavoidable" effects of the Proposed Amendments, and the LCFS regulation generally, it must include, as an alternative in a recirculated EA.[15] (Pub. Resources Code, § 21002.) B4-50

The EA, however, rejects the WSPA Alternative from inclusion as an alternative under CEQA because it would supposedly not meet the project objectives. (See EA at 208.) This is not accurate. First, the assertion that the WSPA Alternative would not reduce the CI of transportation fuels by 20% of 2010 levels by 2030 is not supported by any citation to evidence. And even if this were so, WSPA contemplates that the Cap & Trade Program would be modified to reduce the CI of transportation fuels further. Moreover, CARB has previously noted that an alternative based upon the adaptation of the Cap & Trade program would achieve the same

14 The EA refers to this alternative as the "No LCFS Alternative," even though it actually contemplates the LCFS would be replaced by modifications to the Cap & Trade program. (See EA at 208.) Growth Energy also notes that this alternative is similar to that presented by Growth Energy in connection with the 2015 rulemaking, which CARB also impermissibly rejected.

15 It should also be noted that the WSPA Alternative would not result in fuel shuffling. (See Appendix A, Attachment 2.)

emissions reductions contemplated under the LCFS and ADF regulations. (See CARB 2015 SRIA at 26-27.)

The EA also suggests the WSPA Alternative would not promote "greater diversification of the State's fuel portfolio," or promote "greater innovation and development of cleaner fuels." (EA at 208.) Again, there is no evidence in support of these assertions. In any event, the WSPA Alternative would provide market-based incentives to diversify alternative fuels, (Appendix A, Attachment 2), which we understand CARB itself has used to promote innovation in the fuel sector. (*Id.*) The WSPA Alternative also would not modify, foreclose or otherwise eliminate any pathways to the commercialization of alternative fuels.[16]

Even if the EA could conclude that the WSPA Alternative would not meet some of the project objectives, this conclusion alone does not provide a sufficient basis to exclude consideration of the alternative. The CEQA Guidelines themselves do not require that a proposed alternative meet all of the project objectives. (CEQA Guidelines, § 15126.6(c); *Mira Mar*, *supra*, 119 Cal.App.4th at 489.) Rather, a feasible alternative that would substantially reduce the project's significant impacts should not be excluded from the analysis simply because it would not fully achieve the project's objectives.[17] (See *Habitat & Watershed Caretakers v. City of Santa Cruz* (2013) 213 Cal.App.4th 1277, 1304.) Here, as discussed above, the WSPA Alternative would essentially eliminate all of the "significant and unavoidable" impacts of the Regulations.

B4-50 cont.

16 The EA also suggests the WSPA Alternative would not reduce dependence on petroleum, or decrease volatility in oil prices. (EA at 208.) Again, there is no evidence in support of these statements in the record.

17 This is particularly true given that, in its solicitation of comments, it does not appear that it's the asserted project objectives were articulated to the public in a manner that allowed the public to use these objectives to propose feasible alternatives to CARB.

Further, to the extent the EA relies upon this objective to reject mere analysis of the WSPA Alternative, this would not be consistent with CEQA because it would essentially limit the range of alternatives described to regulations that are nearly identical to the Proposed Amendments. Because agencies may not "give a project's purpose an artificially narrow definition," (*In re Bay-Delta Programmatic Envt'l Report Coordinated Proceedings* (2008) 43 Cal.4th 1143, 1166), and we believe it is important that CARB seek to avoid any argument that it is prejudging the continued implementation of the LCFS regulation prior to completing the environmental review process, (see *POET I, supra*, 218 Cal.App.4th at 714-26), CARB should eliminate any appearance that it is artificially tailoring its objectives to limit the range of alternatives to variations of the LCFS regulation. (See, e.g., *North Coast Rivers Alliance v. Kawamura* (2015) 243 Cal.App.4th 647.) B4-50 cont.

In short, the WSPA Alternative better achieves the project objectives than the Proposed Amendments, and is environmentally superior to the project at hand. As a result, the EA must analyze the WSPA Alternative and be recirculated for public comment.

E15 Alternative. In addition to considering E15 as an alternative under the APA, the E15 Alternative should also be considered as a project alternative under CEQA. Specifically, the requirement that environmental documents identify and discuss alternatives to the project stems from the fundamental statutory policy that public agencies should require the implementation of feasible alternatives or mitigation measures to reduce the project's significant impacts. (See, e.g., Pub. Resources Code, § 21001.) As such, the lead agency must focus on alternatives that can avoid or substantially lessen a project's significant environmental effects. (Pub. Resources Code, § 21002.) The CEQA Guidelines specifically recognize that comments raised by members of the public on an environmental document are particularly helpful if they suggest "additional B4-51 specific alternatives . . . that would provide better ways to avoid or mitigate the significant environmental effects." (CEQA Guidelines, § 15204.)

In addition, Section 15043 of the CEQA Guidelines provides that a "public agency may approve a project even though the project would cause a significant effect on the environment" ***only if*** the agency makes a finding that (a) there "is no feasible way to lessen or avoid the significant effect," ***and*** (b) the benefits of the project outweigh the policy of reducing or avoiding the project's significant environmental impacts. (CEQA Guidelines, § 15043.) This is important in the context of E15 because, on the one hand, an alternative that incorporates E15 would authorize a "greater use of low CI ethanol" that would reduce greenhouse gas emissions. On the other hand, by incorporating a fuel that is already in widespread use throughout the United States, the E15 Alternative would allow existing ethanol plants to meet much of the higher demand for ethanol in E15, thus minimizing the environmental effects found "significant and unavoidable" in the EA. B4-51 cont.

In short, because the EA states the Proposed Amendments would result in "significant and unavoidable" effects due to the construction of new and/or modified facilities, and the E15 Alternative would lessen the need for such facilities, CARB should incorporate the E15 Alternative as a project alternative under CEQA, and approve the E15 alternative instead of the Proposed Amendments. (See CEQA Guidelines, § 15043.)

The EA Should Consider Alternatives Other than the Continuation of the LCFS. The EA does not discuss a reasonable range of alternatives. Specifically, each of the project alternatives identified in the EA is simply some iteration of the LCFS regulation. Alternative 1 is the continuation of the existing LCFS; Alternative 2 is a version of the LCFS with greater CI reductions; Alternative 3 is the LCFS without biodiesel; Alternative 4 is the LCFS without the B4-52

Carbon Capture and Sequestration Protocol; and Alternative 5 is the LCFS without alternative jet fuels. This does not represent a reasonable range of alternatives because none of the alternatives contemplates a regulation that does not substantially resemble the current LCFS.

To range of alternatives should be expanded to ensure compliance with CEQA. By limiting the alternatives to minor variations to the same project, the EA does not promote informed decision-making and public participation, (CEQA Guidelines, § 16126.6, subds. (a)-(f); *Bay Area Citizens v. Assoc. of Bay Area Govts.* (2016) 248 Cal.App.4th 966, 1018; *Fed. of Hillside & Cyn. Ass'ns, supra*, 83 Cal.App.4th at 1264), and essentially makes the continuation of the LCFS a predetermined outcome. This is particularly true given that the "no project" alternative contemplates a continuation of the LCFS regulation in its current form.

To avoid the danger of what now appears to be irreversible momentum associated with the continuation of the LCFS regulation,[18] the range of alternatives should be expanded to include an alternative that does not involve continuation of the LCFS regulation.

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The EA's Formulation of Project Objectives. To the extent the EA relies upon the project objectives to reject ***all*** alternatives other than the continuation of the LCFS, the project objectives are far too narrowly drawn. CEQA requires that an environmental document include a statement of project objectives to help identify the purpose of a project. (See, e.g., CEQA Guidelines, § 15124(b); *Ctr. for Biological Diversity v. County of San Bernardino* (2016) 247 Cal.App.4th 326, 347.) The project objectives are used, *inter alia*, to evaluate the mitigation measures and alternatives identified in the environmental document. (See, e.g., CEQA

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18 *Cf. POET II, supra*, 12 Cal.App.5th 52, 96 ["Plaintiffs' arguments about bureaucratic momentum are realistic and have some merit."]; *Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1203 ["Has the danger of irreversible momentum in favor of the shopping centers . . . been realized?"] [citing *San Joaquin Raptor, supra*, 27 Cal.App.4th at 742].

B4-52 continued from above

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Guidelines, §§ 15126(a), 15126.4(a)(1).) While agencies have some discretion in formulating a project's objectives, CEQA prohibits a lead agency from giving "a project's purpose an artificially narrow definition." (*Bay–Delta, supra,* 43 Cal.4th at 1166; see also *North Coast Rivers Alliance*, *supra*, 243 Cal.App.4th at 668.)

Since 2009, CARB has used its narrowly-drawn project objectives to reject project alternatives that would have reduced the environmental effects of the LCFS regulation. In this rulemaking, the EA again relies upon narrow project objectives, (see EA at 200), to reject alternatives other than some iteration of the LCFS. (*Cf.* EA at 201-07 *with id.* at 207-08.) To avoid an inference that the continuation of the LCFS program is a foregone conclusion, the project objectives should be aligned with the statutory objectives identified in AB 32 and SB 32 to allow alternatives in the EA other than variations of the LCFS program. B4-53 cont.

5. Accuracy of CIs of Various Alternative Fuels under the LCFS Regulation

As explained above, if CARB implements an LCFS program that inaccurately states the CI for any particular fuel, this will send the wrong "signal" to the downstream regulated parties, resulting in the use of fuels that result in higher GHG emissions. For example, if CARB overestimates the CI for an alternative fuel, it disincentivizes the use of that fuel in favor of other fuels with higher carbon intensity, increasing GHG emissions beyond what they would be under a more accurate LCFS regulation. Alternatively, if CARB underestimates the CI of alternative fuel or electricity, it encourages the use of a more carbon-intensive fuel at the expense of other fuels with lower carbon intensity, likewise increasing GHG emissions. Thus, to avoid unnecessary GHG emissions, it is critically important that CARB accurately calculate the CI of alternative fuels and electricity. B4-54

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It does not appear that the Proposed Amendments contemplate an accurate CI for corn starch ethanol, which remains far higher than the evidence supports. Likewise, the CI for Brazilian sugarcane ethanol and electricity are significantly understated. To avoid unnecessary GHG emissions, CARB must correct each of the issues below:

B4-54a

- As explained above and in Appendix D, using CARB's AEZ-EF model in conjunction with GTAP to estimate emissions associated with the various land use changes, researchers have determined that the ILUC for corn starch ethanol should be reduced from 19.8 g/MJ to 10.3 g/MJ. (See *supra*, § II.A.)
- The current ILUC for corn starch ethanol is based on 2011 conditions, which correspond to a drought year in the U.S. that negatively impacted corn yields. When a three-year average is used, the ILUC should be reduced significantly. (See *supra*, § II.A; see also Appendix E.)

B4-54b

- Unlike the Proposed Amendments, the most current version of the GREET model includes a distillers' grains (DDG) methane avoidance credit, which equals 2.1 g/MJ, and which is not incorporated into CA GREET 3.0 under the Proposed Amendments. (See *supra*, § II.A; see also Appendix E.)

B4-54c

- The CI for corn starch ethanol under CA GREET 3.0 contains a value for the electricity that is used in transportation and distribution with an emission factor developed using US average power, even though most such emissions are likely to be in California. (See *supra*, § II.B; see also Appendix E.)

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- The CI for sugarcane does not include GHG emissions associated with ash that is trucked out to sugarcane fields and distributed on the ground to add nutrients back to the soil. (See *supra*, § II.A; see also Appendix D.) B4-54d

- The CI for sugarcane is understated because the nitrogen content of biomass and fertilizer for sugarcane are far higher than estimated by CARB. (See *supra*, § II.A; see also Appendix E.) B4-54e

- CA GREET 3.0 uses the same emission factor for truck transport in Brazil and California, even though Brazil should be higher. (See *supra*, § II.A; see also Appendix D.) B4-54f

- CA GREET 3.0 uses simplified calculators for corn ethanol and sugarcane ethanol that contain several errors. Unless corrected, the CI for sugarcane ethanol will be understated, and the CI for corn will be overstated. (See *supra*, § II. A.; See also Appendix F.) B4-54g

- The EER for electricity is far too high because the estimates were generated based on testing performed with accessory modes off. (See *supra*, § II.C; see also Appendix B.) B4-54h

- The EER for electricity is also too high because it is based on optimal temperature (75°-80°) for battery efficiency, and not real world conditions. (See *supra*, § II.C; see also Appendix B.) B4-54i

- The EERs for numerous vehicles are overstated. (See *supra*, § II.C; see also Appendix B at 13.) B4-54j

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- The Proposed Amendments do not allow CI reduction for dedicated renewable electricity unless the generation facilities are co-located with the fuel production facility, removing incentives for fuel producers to develop renewable sources for process energy. Elsewhere, the ISOR states the goal of "incent[ing] the installation of additional low carbon electricity supply" would result in greater greenhouse gas benefits. (ISOR at EX-5.) As such, CARB should consider the impacts associated with not applying the same rules to process energy for fuel providers. B4-54k

Each of the above issues has a material impact on the CI for the affected fuel. Cumulatively, correction of the above issues changes the CI dramatically. Thus, to avoid unnecessary increases in GHGs, CARB should resolve the above issues prior to certifying the EA and approving the Proposed Amendments. B4-54l

6. The EA's Identification of Mitigation Measures

Attachment 2 to the EA includes a summary of environmental impacts and mitigation measures. (See EA, Attachment 2.) The document is structured in a manner similar to a Mitigation Monitoring and Reporting Program, although that is not what the attachment is entitled. Attachment 2, among other things, summarizes the mitigation measures identified in the EA. Each of the proposed mitigation measures should be augmented to ensure compliance with CEQA. B4-55

Legally Enforceable Mitigation Measures. As explained above, CEQA requires mitigation measures to be enforceable through means that are legally binding. (Pub. Resources Code, § 21081.6(b); CEQA Guidelines, § 15126.4.) This requirement is designed to ensure that mitigation measures will actually be implemented. (*Fed. of Hillside & Cyn. Ass'ns*, *supra*, 83 B4-56

Cal.App.4th at 1261; *Anderson First*, *supra*, 130 Cal.App.4th at 1186.) The following mitigation measures do not represent binding commitments on the part of any person to do anything and therefore fail to ensure that mitigation measures will actually be implemented:

- Mitigation Measure B.1.a states that project proponents "would" take various actions in coordination with State or local land use agencies in seeking entitlements for development. There is nothing in Mitigation Measure B.1.a, however, that ensures the measures identified will actually be implemented. (EA, Attachment 2 at 1-2.)
- Mitigation Measure B.2.a merely states that "actions required to mitigate potentially significant . . . impacts ***may*** include the following actions." (*Id.* at 3.) Several actions are then stated in suggestive terms; however, none of the actions are required to be implemented. Nor are any mandatory performance standards articulated to assess the expected outcome of the measure. (*Id.* at 3-4.)
- Mitigation Measures B.4.a, B.5.a, C.6.b, B.7.a, B.9.a, B.10.a, C.12.b, 13.a, 17.a, B.18.a, merely state that "actions required to mitigate potentially significant . . . impacts ***may*** include the following; however, ***any mitigation specifically required*** for a new or modified facility ***would be determined by the local lead agency.***" (*Id.* at 10, 13 [emphasis added].) There is nothing in any of the above-referenced mitigation measures, however, that ensures the measures identified will actually be implemented.

B4-56 cont.

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- Mitigation Measures B.7.b and C.12.b merely identify "[r]ecognized practices that are routinely required to avoid and/or minimize impacts." (*Id.* at 20, 35.) But they do not require that those practices actually be implemented.
- Mitigation Measures B.10.b and B.17.b merely identify various activities without requiring that the activities actually be performed. (*Id.* at 29-30, 43-44.)

B4-56 cont.

Deferral of Mitigation. The formulation of specific mitigation measures may properly be deferred only if the mitigation measures specify performance standards for mitigating the impact. (See CEQA Guidelines, § 15126.4(a)(1)(B); see also *Sacramento Old City Ass'n v. City Council* (1991) 229 Cal.App.3d 1011; *Endangered Habitats League, Inc. v. County of Orange* (2005) 131 Cal.App.4th 777, 794 [upholding measures that included specific performance criteria and mitigation commitments and rejecting measure that lacked any criteria or standards].) A mitigation performance standard is sufficient if it identifies the criteria the agency will apply in determining that the impact will be mitigated. (See, e.g., *Citizens for a Sustainable Treasure Island v. City & County of San Francisco* (2014) 227 Cal.App.4th 1036, 1059.) Performance standards based on specific objectives that inform the agency "what it is to do and what it must accomplish" are adequate, (see *Center for Biological Diversity, supra*, 234 Cal.App.4th at 245), but "loose or open-ended performance criteria" are not. (*Rialto Citizens for Responsible Growth v. City of Rialto* (2012) 208 Cal.App.4th 899, 945.) The following mitigation measures appear to defer the formulation of specific mitigation measures because they do not include adequate performance criteria:

B4-57

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- Mitigation Measures B.4.a, B.5.a, C.6.b, B.7.a, B.9.a, B.10.a, C.12.b, 13.a, 17.a, B.18.a, merely state that "actions required to mitigate potentially significant. . . impacts ***may*** include the following; however, ***any mitigation specifically required*** for a new or modified facility ***would be determined by the local lead agency.***" (EA, Attachment 2 at 10, 13 [emphasis added].) No performance standards are articulated to assess the expected outcome of these measures.
- Mitigation Measure B.3.a and B.3.b state that future project proponents "would" apply for and secure all necessary permits and comply with all applicable regulations. However, no performance standards are articulated to assess the expected outcome of these measures. (EA, Attachment 2 at 6-7.)
- Mitigation Measures 7.c, C.9.b, and 10.c.(1) merely identify various permits and agreements that "could" reduce environmental impacts, state that to obtain such permits, "the project proponent would be required to conduct various evaluations," and then identifies requirements such permits are "likely to include." (*Id.* at 21-22, 25-26.) However, no performance standards are articulated to assess the expected outcome of these measures. Curiously, the measures also state at the end that "this impact could be reduced," without providing any explanation as to how, or

B4-57 cont.

if so, why additional measures are not being implemented. (*Id.* at 22, 26.)[19] B4-57 continued from previous page, continues to footnote below

Several Mitigation Measures in Attachment 2 Are Inadequately Defined. Courts have held that mitigation measures that are so undefined that it is impossible to gauge their effectiveness are not adequate under CEQA. (See, e.g., *Preserve Wild Santee v. City of Santee* (2012) 210 Cal.App.4th 260, 281.) The mitigation measure for Impact B.11.a simply states "See Mitigation Measures: 2.a, 2.b, 4.a, 4.b, 8.b, and 10.a." It cannot be determined based on this statement to which mitigation measures the analysis is referring the reader. The same error is repeated in the discussion of Impacts C.11.a, B.11.b, and C.11.b. (See EA, Attachment 2 at 32-33.) B4-58

Further, despite the title of Attachment 2 to the EA ["Summary of Environmental Impacts and Mitigation Measures"], it is not clear whether these measures would be used to mitigate any environmental impacts. Instead, the information in Attachment 2 appears to be legal argument, as opposed to mitigation to lessen significant environmental impacts.

V. INCORPORATION OF PRIOR COMMENTS

Growth Energy notes that many of the comments that it submitted in connection with the 2015 rulemaking for the LCFS regulation and the ADF regulation remain relevant to this 2018 rulemaking. As such, Growth Energy is also enclosing its prior comments, and the supporting technical data, in electronic format. B4-59

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19 Unlike the other measures, Mitigation Measure 10.c.(1) states "this impact could be reduced to a less than significant level." (EA, Attachment 2 at 32.) In the next sentence, however, Attachment 2 states that "there is inherent uncertainty in the degree of mitigation ultimately implemented to reduce the potentially significant impacts." (*Id.*) These two statements do not appear to be consistent, and should be reconciled. B4-57 continued from above

VI. CONCLUSION

Growth Energy appreciates the opportunity to participate in this rulemaking. Growth Energy, however, continues to have significant concerns regarding the LCFS regulation and the Proposed Amendments. As a result, Growth Energy requests that CARB staff augment the ISOR (and its appendices) to fully address and consider meaningful alternatives to the LCFS regulation (including the WSPA Alternative and the E15 Alternative). Growth Energy also requests that the ISOR also address each of the other issues raised in these comments in a revised ISOR. Following these revisions, CARB should recirculate the ISOR for public comment. B4-60

APPENDIX "A"

STATE OF CALIFORNIA

BEFORE THE AIR RESOURCES BOARD

Declaration of James M. Lyons

I, James Michael Lyons, declare as follows:

1. I make this Declaration based upon my own personal knowledge and my familiarity with the matters recited herein. It is based on my experience of nearly 30 years as a regulator, consultant, and professional in the field of emissions and air pollution control. A copy of my résumé can be found in **Attachment 1**.

2. I am a Principal Consultant of Trinity Consultants, an environmental consulting firm with offices located at 1801 J Street, Sacramento, California. Among other things, Trinity specializes in research and regulatory matters pertaining to air pollution control, and does work for both governmental and private industry clients. I have been employed at Trinity and its predecessors since 1991. I received a B.S. degree in Chemistry from the University of California, Irvine, and a M.S. Degree in Chemical Engineering from the University of California, Los Angeles. Before joining Sierra in 1991, I was employed by the State of California at the Mobile Source Division of the California Air Resources Board (CARB).

3. During my career, I have worked on many projects related to the following areas: 1) the assessment of emissions from on- and non-road mobile sources, 2) assessment of the impacts of changes in fuel composition and alternative fuels on engine emissions including emissions of green-house gases, 3) analyses of the unintended consequences of regulatory actions, and 4) the feasibility of compliance with air quality regulations.

4. I have testified as an expert under state and federal court rules in cases involving CARB regulations for gasoline, Stage II vapor recovery systems and their design, factors affecting emissions from diesel vehicles, evaporative emission control system design and function, as well as combustion chamber system design. While at Sierra I have acted as a consultant on automobile air pollution control matters for CARB and for the United States Environmental Protection Agency. I am a member of the American Chemical Society and the Society of Automotive Engineers and have co-authored nine peer-reviewed monographs concerned with automotive emissions, including greenhouse gases and their control. In addition, over the course of my career, I have conducted peer-reviews of numerous papers related to a wide variety of issues associated with pollutant emissions and air quality.

5. This Declaration summarizes the results of my review of the CARB's Staff Report: Initial Statement of Reasons, and related documents, concerning the Proposed Amendments to the Low Carbon Fuel Standard Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels, which was released for

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public review on March 6, 2018 (the "ISOR"). I have performed this review as an independent expert for Growth Energy. If called upon to do so, I would testify in accord with the facts and opinions presented here.

6. I have prepared several documents analyzing aspects ISOR, and the proposed amendments to the LCFS regulation and the ADF regulation (the "Proposed Amendments"), which are included as attachments to this declaration:

a. Attached hereto as **Attachment 2** is a true and correct copy of the document I prepared containing an analysis of cap & trade alternatives to the LCFS regulation, including the proposed alternative presented by Western States Petroleum Association. B4-61

b. Attached hereto as **Attachment 3** is a true and correct copy of the document I prepared containing the presentation of an alternative to the LCFS regulation for use in CARB's analysis of alternatives under the APA and CEQA. This alternative contemplates the continuation of the LCFS regulation, with the inclusion of the certification of E15. The inclusion of E15 into the LCFS regulation would lessen the significant and unavoidable effects associated with the construction of new or modified facilities, and would also achieve the greenhouse emissions reductions desired by CARB. B4-62

c. Attached hereto as **Attachment 4** is a true and correct copy of the document I prepared containing my review of issues relating to the analysis of biodiesel use in California under the LCFS program. B4-63

d. Attached hereto as **Attachment 5** is a true and correct copy of the document I prepared containing an analysis of potential impacts associated with new and modified facilities associated with the LCFS regulation, including potential mitigation. B4-64

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 26th day of April, 2018 at Sacramento, California.

JAMES M. LYONS

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Declaration of James M. Lyons

Attachment 1

James Lyons

***Principal Consultant* – Sacramento Office**

Trinity Consultants

AREAS OF SPECIALIZATION

- New Vehicle and Engine Certification
- Development and Assessment of Mobile Source Emission Control Strategies
- Development and Assessment of Strategies for Reduction of Criteria Pollutant and GHG Emissions Related to Transportation Fuels – Including Alternative Fuels and Fuel Additives
- Design and Implementation of Vehicle Testing Programs and Data Analysis
- Enforcement and Litigation Support Related to Mobile Sources and Transportation Fuels
- Intellectual Property Disputes Involving Engine and Emission Control System Design, Function, and Novelty
- Tracking and Reporting of California Air Resources Board Activities Related to the Regulation of Mobile Source Emissions and Transportation Fuels
- Emission Inventories and Quantification

EDUCATION

M.S., Chemical Engineering, University of California, Los Angeles
B.S., Cum Laude, Chemistry, University of California, Irving

AFFILIATIONS

Society of Automotive Engineers
American Chemical Society

SUMMARY OF EXPERIENCE

A Principal Consultant and head of Trinity's Mobile Source and Fuels team, Mr. Lyons has extensive experience related to fuels issues and emissions, including the emission impacts of changes in gasoline and diesel fuel composition and substitution of alternative fuels for petroleum-based fuels. Specific projects have required work on issues related to the emissions impacts of changes in gasoline and diesel fuel as well as compliance with California Air Resources Board (CARB) and U.S. EPA regulations related to gasoline and diesel fuel properties and specifications, assessment of costs and benefits of alternative fuels and alternatively fueled vehicles, and direct involvement in analyses of issues related to CARB and EPA fuels regulations, including the Renewable Fuel Standards (RFS) and Low Carbon Fuel Standards. He has also provided expert services in fuels-related litigations.

Additional responsibilities include oversight and execution of complex analyses of the emission benefits, costs, and cost-effectiveness of mobile source air pollution control measures. Mr. Lyons has developed particular expertise with respect to the assessment of control measures involving accelerated vehicle/engine retirement programs; the deployment of advanced emission control systems, including electric fuel cell and hybrid technologies for on- and non-road gasoline- and diesel-powered vehicles and engines, as well as on-vehicle evaporative and refueling emission control systems. Other duties include assessments of the activities of federal, state, and local regulatory agencies with respect to motor vehicle emissions and reports to clients regarding those activities. Mr. Lyons has extensive litigation experience related to air quality and fuels including gasoline property and renewable fuels regulations, product liability, and intellectual property issues.

TECHNICAL EXPERTISE

Fuels Regulations. Managed numerous projects related to assessments of Low Carbon Fuel Standard (LCFS) regulations adopted or being prepared by California and a number of other jurisdictions. Has also been involved in the review of reformulated gasoline and diesel fuel regulations, including the federal RFS 1, RFS 2, and Tier 3 regulations.

Mobile Source Emissions Control. Participated in the design and evaluation of mobile source emission control measures and emission control systems; development of mobile source emissions modeling software; development of mobile source emission inventories; design and management of supporting field and laboratory studies; and the design and evaluation of vehicle emissions inspection and maintenance programs. Mobile source categories include on- and off-road vehicles, locomotives, marine vessels, and aircraft. Directly involved in assessing changes in vehicle technology required to comply with federal, California, and Mexican new-vehicle greenhouse gas and fuel economy standards for light-duty vehicles.

New Vehicle and Engine Certification. Directly participated in and managed efforts related to obtaining U.S. EPA and California Air Resources Board certification for new engines and vehicles, including activities related to agency enforcement actions and on-going compliance requirements.

Air Quality Planning and Strategy Development. Has been involved in the development and critical assessment of mobile source and transportation fuels elements of State Implementation Plans.

Emission Control System Design and Evaluation. Provided support for the design and assessment of alternative emission control techniques, and for troubleshooting control system issues. Issues assessed have include VOC, CO, NOx, SOx, and PM control systems in various applications.

Expert Witness Services. Presented testimony and served as an expert or consulting expert on numerous cases in federal and state courts involving issues related to government regulations affecting mobile source certifications, in-use emissions issues, fuel regulations, intellectual property issues related to emission controls and fuels, and product liability.

EMPLOYMENT HISTORY

2014 – Present	Trinity Consultants
1991 – 2014	Sierra Research
1985 – 1991	California Air Resources Board

SELECTED PUBLICATIONS (AUTHOR OR CO-AUTHOR)

"Follow-On Study of Transportation Fuel Life Cycle Analysis: Review of Current CARB and EPA Estimates of Land Use Change (LUC) Impacts," Sierra Research Report No. SR2016-08-01, prepared for the Coordinating Research Council, CRC Project No. E-88-3b, August 2016.

"Review of EPA's MOVES2014 Model," Sierra Research Report No. SR2016-07-01, prepared for the Coordinating Research Council, CRC Project No. E-101, July 2016.

"Development of Vehicle Attribute Forecasts for the '2015 Integrated Energy Policy Report,'" prepared for the California Energy Commission, February 5, 2016.

"Sensitivity Analysis of Key Assumptions on Energy and Environmental Economics (E3) 'California Pathways GHG Scenario Results' as They Pertain to the Light-Duty Vehicle Sector," prepared for the Alliance of Automobile Manufacturers, October 2015.

"Review of Energy and Environmental Economics (E3) "California Pathways GHG Scenario Results" as They Pertain to the Light-Duty Vehicle Sector," prepared for the Alliance of Automobile Manufacturers, October 2015.

"International Light-Duty Vehicle Fuel Economy and Greenhouse Gas Standards Analysis," prepared for the Alliance of Automobile Manufacturers, July 2015.

James Lyons
Principal Consultant – Sacramento Office

Trinity Consultants

"Quantifying Aircraft Lead Emissions at Airports," prepared for the Transportation Research Board, Airport Cooperative Research Program, October 2014.

"Best Practices Guidebook for Preparing Lead (Pb) Emission Inventories from Piston-Powered Aircraft," prepared for the Transportation Research Board, Airport Cooperative Research Program, October 2014.

"Development of Vehicle Attribute Forecasts for 2013 IEPR," Sierra Research Report No. SR2014-01-01, prepared for the California Energy Commission, January 2014.

"Assessment of the Emission Benefits of U.S. EPA's Proposed Tier 3 Motor Vehicle Emission and Fuel Standards," Sierra Research Report No. SR2013-06-01, prepared for the American Petroleum Institute, June 2013.

"Development of Inventory and Speciation Inputs for Ethanol Blends," Sierra Research Report No. SR2012-05-01, prepared for the Coordinating Research Council, Inc. (CRC), May 2012.

"Review of CARB Staff Analysis of 'Illustrative' Low Carbon Fuel Standard (LCFS) Compliance Scenarios," Sierra Research Report No. SR2012-02-01, prepared for the Western States Petroleum Association, February 20, 2012.

"Review of CARB On-Road Heavy-Duty Diesel Emissions Inventory," Sierra Research Report No. SR2010-11-01, prepared for The Ad Hoc Working Group, November 2010.

"Identification and Review of State/Federal Legislative and Regulatory Changes Required for the Introduction of New Transportation Fuels," Sierra Research Report No. SR2010-08-01, prepared for the American Petroleum Institute, August 2010.

"Technical Review of EPA Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis for Non-GHG Pollutants," Sierra Research Report No. SR2010-05-01, prepared for the American Petroleum Institute, May 2010.

"Effects of Gas Composition on Emissions from Heavy-Duty Natural Gas Engines," Sierra Research Report No. SR2010-02-01, prepared for the Southern California Gas Company, February 2010.

"Effects of Gas Composition on Emissions from a Light-Duty Natural Gas Vehicle," Sierra Research Report No. SR2009-11-01, prepared for the Southern California Gas Company, November 2009.

"Technical Review of 2009 EPA Draft Regulatory Impact Analysis for Non-GHG Pollutants Due to Changes to the Renewable Fuel Standard," Sierra Research Report No. SR2009-09-01, prepared for the American Petroleum Institute, September 2009.

"Effects of Vapor Pressure, Oxygen Content, and Temperature on CO Exhaust Emissions," Sierra Research Report No. 2009-05-03, prepared for the Coordinating Research Council, May 2009.

"Technical Review of 2007 EPA Regulatory Impact Analysis Methodology for the Renewable Fuels Standard," Sierra Research Report No. 2008-09-02, prepared for the American Petroleum Institute, September 2008.

"Impacts of MMT Use in Unleaded Gasoline on Engines, Emission Control Systems, and Emissions," Sierra Research Report No. 2008-08-01, prepared for McMillan Binch Mendelsohn LLP, Canadian Vehicle Manufacturers' Association, and Association of International Automobile Manufacturers of Canada, August 2008.

"Attachment to Comments Regarding the NHTSA Proposal for Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015, Docket No. NHTSA-2008-0089," Sierra Research Report No. SR2008-06-01, prepared for the Alliance of Automobile Manufacturers, June 2008.

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act – Part 1: Impacts on New Vehicle Fuel Economy," SAE Paper No. 2008-01-1852, Society of Automotive Engineers, 2008.

"Basic Analysis of the Cost and Long-Term Impact of the Energy Independence and Security Act Fuel Economy Standards," Sierra Research Report No. SR 2008-04-01, April 2008.

"The Benefits of Reducing Fuel Consumption and Greenhouse Gas Emissions from Light-Duty Vehicles," SAE Paper No. 2008-01-0684, Society of Automotive Engineers, 2008.

"Assessment of the Need for Long-Term Reduction in Consumer Product Emissions in South Coast Air Basin," Sierra Research Report No. 2007-09-03, prepared for the Consumer Specialty Products Association, September 2007.

"Summary of Federal and California Subsidies for Alternative Fuels," Sierra Research Report No. SR2007-04-02, prepared for the Western States Petroleum Association, April 2007.

"Analysis of IRTA Report on Water-Based Automotive Products," Sierra Research Report No. SR2006-08-02, prepared for the Consumer Specialty Projects Association and Automotive Specialty Products Alliance, August 2006.

"Evaluation of Pennsylvania's Implementation of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2006-04-01, prepared for Alliance of Automobile Manufacturers, April 12, 2006.

"Evaluation of New Jersey's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-03, prepared for the Alliance of Automobile Manufacturers, September 30, 2005.

"Evaluation of Vermont's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-02, prepared for the Alliance of Automobile Manufacturers, September 19, 2005.

"Assessment of the Cost-Effectiveness of Compliance Strategies for Selected Eight-Hour Ozone NAAQS Nonattainment Areas," Sierra Research Report No. SR2005-08-04, prepared for the American Petroleum Institute, August 30, 2005.

"Evaluation of Connecticut's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-08-03, prepared for the Alliance of Automobile Manufacturers, August 26, 2005.

"Evaluation of New York's Adoption of California's Greenhouse Gas Regulations On Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-07-04, prepared for the Alliance of Automobile Manufacturers, July 14, 2005.

"Review of MOVES2004," Sierra Research Report No. SR2005-07-01, prepared for the Alliance of Automobile Manufacturers, July 11, 2005.

"Review of Mobile Source Air Toxics (MSAT) Emissions from On-Highway Vehicles: Literature Review, Database, Development, and Recommendations for Future Studies," Sierra Research Report No. SR2005-03-01, prepared for the American Petroleum Institute, March 4, 2005.

"The Contribution of Diesel Engines to Emissions of ROG, NOx, and PM2.5 in California: Past, Present, and Future," Sierra Research Report No. SR2005-02-01, prepared for Diesel Technology Forum, February 2005.

"Fuel Effects on Highway Mobile Source Air Toxics (MSAT) Emissions," Sierra Research Report No. SR2004-12-01, prepared for the American Petroleum Institute, December 23, 2004.

"Review of the August 2004 Proposed CARB Regulations to Control Greenhouse Gas Emissions from Motor Vehicles: Cost Effectiveness for the Vehicle Owner or Operator – Appendix C to the Comments of The Alliance of Automobile Manufacturers," Sierra Research Report No. SR2004-09-04, prepared for the Alliance of Automobile Manufacturers, September 2004.

"Emission and Economic Impacts of an Electric Forklift Mandate," Sierra Research Report No. SR2003-12-01, prepared for National Propane Gas Association,
December 12, 2003.

"Reducing California's Energy Dependence," Sierra Research Report No. SR2003-11-03, prepared for Alliance of Automobile Manufacturers, November 25, 2003.

"Evaluation of Fuel Effects on Nonroad Mobile Source Air Toxics (MSAT) Emissions: Literature Review, Database Development, and Recommendations for Future Studies," Sierra Research Report No. SR2003-10-01, prepared for American Petroleum Institute, October 3, 2003.

"Review of Current and Future CO Emissions from On-Road Vehicles in Selected Western Areas," Sierra Research Report No. SR03-01-01, prepared for the Western States Petroleum Association, January 2003.

"Review of CO Compliance Status in Selected Western Areas," Sierra Research Report No. SR02-09-04, prepared for the Western States Petroleum Association, September 2002.

"Impacts Associated With the Use of MMT as an Octane Enhancing Additive in Gasoline – A Critical Review", Sierra Research Report No. SR02-07-01, prepared for Canadian Vehicle Manufacturers Association and Association of International Automobile Manufacturers of Canada, July 24, 2002.

"Critical Review of 'Safety Oversight for Mexico-Domiciled Commercial Motor Carriers, Final Programmatic Environmental Assessment', Prepared by John A Volpe Transportation Systems Center, January 2002," Sierra Research Report No. SR02-04-01, April 16, 2002.

"Critical Review of the Method Used by the South Coast Air Quality Management District to Establish the Emissions Equivalency of Heavy-Duty Diesel- and Alternatively Fueled Engines", Sierra Research Report No. SR01-12-03, prepared for Western States Petroleum Association, December 21, 2001.

"Review of U.S. EPA's Diesel Fuel Impact Model", Sierra Research Report No. SR01-10-01, prepared for American Trucking Associations, Inc., October 25, 2001.

"Operation of a Pilot Program for Voluntary Accelerated Retirement of Light-Duty Vehicles in the South Coast Air Basin," Sierra Research Report No. SR01-05-02, prepared for California Air Resources Board, May 2001.

"Comparison of Emission Characteristics of Advanced Heavy-Duty Diesel and CNG Engines," Sierra Report No. SR01-05-01, prepared for Western States Petroleum Association, May 2001.

"Analysis of Southwest Research Institute Test Data on Inboard and Sterndrive Marine Engines," Sierra Report No. SR01-01-01, prepared for National Marine Manufacturers Association, January 2001.

"Institutional Support Programs for Alternative Fuels and Alternative Fuel Vehicles in Arizona: 2000 Update," Sierra Report No. SR00-12-04, prepared for Western States Petroleum Association, December 2000.

"Real-Time Evaporative Emissions Measurement: Mid-Morning Commute and Partial Diurnal Events," SAE Paper No. 2000-01-2959, October 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," SAE Paper No. 2000-01-2958, October 2000.

"A Comparative Analysis of the Feasibility and Cost of Compliance with Potential Future Emission Standards for Heavy-Duty Vehicles Using Diesel or Natural Gas," Sierra Research Report No. SR00-02-02, prepared for Californians For a Sound Fuel Strategy, February 2000.

"Critical Review of the Report Entitled 'Economic Impacts of On Board Diagnostic Regulations (OBD II)' Prepared by Spectrum Economics," Sierra Research Report No. SR00-01-02, prepared for the Alliance of Automobile Manufacturers, January 2000.

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"Evaporative Emissions from Late-Model In-Use Vehicles," Sierra Research Report No. SR99-10-03, prepared for the Coordinating Research Council, October 1999.

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"Analysis of Compliance Feasibility under Proposed Tier 2 Emission Standards for Passenger Cars and Light Trucks," Sierra Research Report No. SR99-07-02, July 1999.

"Comparison of the Properties of Jet A and Diesel Fuel," Sierra Research Report No. SR99-02-01, prepared for Pillsbury Madison and Sutro, February 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," Sierra Research Report No. SR98-12-02, prepared for the American Petroleum Institute, December 1998.

"Analysis of New Motor Vehicle Issues in the Canadian Government's Foundation Paper on Climate Change – Transportation Sector," Sierra Research Report No. SR98-12-01, prepared for the Canadian Vehicle Manufacturers Association, December 1998.

"Investigation of the Relative Emission Sensitivities of LEV Vehicles to Gasoline Sulfur Content - Emission Control System Design and Cost Differences," Sierra Research Report No. SR98-06-01, prepared for the American Petroleum Institute, June 1998.

"Costs, Benefits, and Cost-Effectiveness of CARB's Proposed Tier 2 Regulations for Handheld Equipment Engines and a PPEMA Alternative Regulatory Proposal," Sierra Research Report No. SR98-03-03, prepared for the Portable Power Equipment Manufacturers Association, March 1998.

"Analysis of Diesel Fuel Quality Issues in Maricopa County, Arizona," Sierra Research Report No. SR97-12-03, prepared for the Western States Petroleum Association, December 1997.

"Potential Impact of Sulfur in Gasoline on Motor Vehicle Pollution Control and Monitoring Technologies," prepared for Environment Canada, July 1997.

"Analysis of Mid- and Long-Term Ozone Control Measures for Maricopa County," Sierra Research Report No. SR96-09-02, prepared for the Western States Petroleum Association, September 9, 1996.

"Technical and Policy Issues Associated with the Evaluation of Selected Mobile Source Emission Control Measures in Nevada," Sierra Research Report No. SR96-03-01, prepared for the Western States Petroleum Association, March 1996.

"Cost-Effectiveness of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-05, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"Cost of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-04, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"A Comparative Characterization of Gasoline Dispensing Facilities With and Without Vapor Recovery Systems," Sierra Research Report No. SR95-10-01, prepared for the Province of British Columbia Ministry of Environment Lands and Parks, October 1995.

"Potential Air Quality Impacts from Changes in Gasoline Composition in Arizona," Sierra Research Report No. SR95-04-01, prepared for Mobil Corporation, April 1995.

"Vehicle Scrappage: An Alternative to More Stringent New Vehicle Standards in California," Sierra Research Report No. SR95-03-02, prepared for Texaco, Inc., March 1995.

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"Meeting ZEV Emission Limits Without ZEVs," Sierra Research Report No. SR94-05-06, prepared for Western States Petroleum Association, May 1994.

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"Searles Valley Air Quality Study (SVAQS) Final Report," Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

"A Comparative Study of the Effectiveness of Stage II Refueling Controls and Onboard Refueling Vapor Recovery," Sierra Research Report No. SR93-10-01, prepared for the American Automobile Manufacturers Association, October 1993.

"Evaluation of the Impact of the Proposed Pole Line Road Overcrossing on Ambient Levels of Selected Pollutants at the Calgene Facilities," Sierra Research Report No. SR93-09-01, prepared for the City of Davis, September 1993.

"Leveling the Playing Field for Hybrid Electric Vehicles: Proposed Modifications to CARB's LEV Regulations," Sierra Research Report No. SR93-06-01, prepared for the Hybrid Vehicle Coalition, June 1993.

"Size Distributions of Trace Metals in the Los Angeles Atmosphere," *Atmospheric Environment*, Vol. 27B, No. 2, pp. 237-249, 1993.

"Preliminary Feasibility Study for a Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley Area," Sierra Research Report No. 92-10-01, prepared for the Greater Vancouver Regional District, October 1992.

"Development of Mechanic Qualification Requirements for a Centralized I/M Program," SAE Paper No. 911670, 1991.

"Cost-Effectiveness Analysis of CARB's Proposed Phase 2 Gasoline Regulations," Sierra Research Report No. SR91-11-01, prepared for the Western States Petroleum Association, November 1991.

"Origins and Control of Particulate Air Toxics: Beyond Gas Cleaning," in Proceedings of the Twelfth Conference on Cooperative Advances in Chemical Science and Technology, Washington, D.C., October 1990.

"The Effect of Gasoline Aromatics on Exhaust Emissions: A Cooperative Test Program," SAE Paper No. 902073, 1990.

"Estimation of the Impact of Motor Vehicles on Ambient Asbestos Levels in the South Coast Air Basin," Paper No. 89-34B.7, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"Benzene/Aromatic Measurements and Exhaust Emissions from Gasoline Vehicles," Paper No. 89-34B.4, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

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"Exhaust Benzene Emissions from Three-Way Catalyst-Equipped Light-Duty Vehicles," Paper No. 87-1.3, presented at the 80th Annual Meeting of the Air Pollution Control Association, New York, NY, June 1987.

"Trends in Emissions Control Technologies for 1983-1987 Model-Year California-Certified Light-Duty Vehicles," SAE Paper No. 872164, 1987.

Declaration of James M. Lyons

Attachment 2

Attachment 2

CARB Staff's Analysis of Alternatives to the Proposed 2018 LCFS Regulation

The regulatory documents for the proposed 2018 LCFS amendments to the Low Carbon Fuel Standard (LCFS) regulation contain several alternatives that CARB staff purport to have analyzed, which are primarily iterations of the LCFS regulation. These include the following alternatives discussed in Sections VII and IX of the ISOR:[1]

1. Establishing a 25% CI reduction standard for 2030 instead of the proposed 20% using a linear decrease over time from the 2018 reduction requirement of 5% to establish CI reduction standards for interim years;
2. Establishing a 18% CI reduction standard for 2030 without changing the current CI reduction standards for 2018 to 2020 with a linear decrease overtime to establish CI reduction standards for interim years;
3. CARB also declined to include as an alternative a proposal from WSPA to eliminate the LCFS and rely instead on the Cap-and-Trade regulation to achieve the desired reductions in GHG emissions from the transportation sector while also providing financial incentives to encourage the production of low CI transportation fuels;
4. CARB also declined to include as formal alternatives proposals from Pacific Gas and Electric and Chevron that the 2030 CI reduction standard be set at 15%.

B4-65

Only one of the above alternatives, the 25% CI reduction standard for 2030 (number 1 above) is included as a project alternative in the Draft Environmental Analysis (Appendix D to the ISOR)[2] which also adds the following alternatives that are not discussed in the ISOR:

5. A no project alternative where the current LCFS regulation is left in place without modification;
6. Exempting biodiesel from the LCFS regulation;
7. Excluding the proposed Carbon Capture and Sequestration Protocol from the LCFS regulation; and
8. Excluding the proposed opt-in Alternative Jet Fuels from the LCFS regulation;

In addition, the EA rejected the WSPA Alternative from inclusion as an alternative under CEQA. Alternatives analysis is also presented in the Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation (Appendix G to the ISOR).[3] This analysis provides a second assessment of the no project alternatives found in Appendix D to the ISOR (number 5 above) and exempting biodiesel from the LCFS

[1] https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf
[2] https://www.arb.ca.gov/regact/2018/lcfs18/appd.pdf
[3] https://www.arb.ca.gov/regact/2018/lcfs18/appg.pdf

Attachment 2

regulation (number 6 above), but are not discussed in the ISOR itself and includes yet another alternative that appears only in Appendix G to the ISOR:

9. Requiring the mitigation of potential increases in NOx emissions associated with all biodiesel sold in California.

The ISOR does not consistently analyzed any of the above alternatives, in particular—the WSPA alternative that would eliminate the LCFS regulation and the alternative that would require mitigation of all potential increases in NOx emission from biodiesel sold in California. B4-65 cont.

The SIRO should be augmented to include a comprehensive and consistent analysis of all suggested alternatives analysis that quantifies the GHG reductions and economic impacts of those alternatives relative to the staff proposal. Further, the evaluation of alternatives across the various documents in the rulemaking should focus on the statutory requirements necessary to achieve reductions in GHG emissions in the most cost-effective manner possible and not reject alternatives because they do not meet subjective and arbitrary criteria that lack foundation in the underlying statutes, including, for example, achievement of "radical" decarbonization of transportation fuels.

CARB Should Consider Cap-and-Trade Alternatives to the LCFS

The WSPA Alternative submitted to CARB is attached at Appendix A and consists of two parts:

- Recognizing that the GHG emission reductions claimed by the LCFS program are already being achieved in large part in a more cost effective manner through the AB 32 Cap-and-Trade program, and
- Addressing the stated need for "innovation and fuel substituting" through the LCFS regulation through a financial incentive program tailored by CARB to satisfy that need.

The EA declines to consider the WSPA alternative, by stating that it was: B4-66

> *...not further analyzed because it is less likely to accomplish the innovation and fuel substituting benefits intended by the LCFS. Future emission reductions far beyond the near term reductions sought by the proposed LCFS or the Cap-and-Trade program will be necessary, and will be feasible only if transportation fuels are radically decarbonized through innovation in low carbon fuel production, distribution and use. The most effective way to achieve this is via programs that directly target transportation fuels. LCFS focuses on transportation fuels with a market approach that also minimizes the cost.*

It should be noted with respect to "minimized cost" that WSPA highlighted in its submission that GHG emission reduction credits under the Cap-and-Trade regulation cost as much as ten times less than GHG emission reduction credits under the LCFS regulation. As a consequence, California consumers are paying over $1.5 billion more per year for GHG reductions under the

Attachment 2

LCFS program than they would have if the Cap-and-Trade regulation had been relied upon to generate the same GHG reductions.

It should also be noted that WSPA's proposal to use financial incentives to promote innovation in the California transportation fuel sector is the same strategy that CARB itself has and is continuing to pursue to accomplish the same goals.[4] Therefore, any criticism of the WSPA proposal in the EA or the ISOR lacks substantial evidence.

Growth Energy proposed a similar alternative that provided a pathway to eliminate the LCFS regulation which is redundant to the Cap-and-Trade regulation during CARB's consideration of the 2015 LCFS amendments. Growth Energy's proposal made as part of the 2015 LCFS rulemaking process, attached as Appendix B, outlined in detail the simple modifications that could be made to the Cap-and-Trade regulation that would assure that the targeted GHG reductions could be realized at a lower cost than with the LCFS regulation remaining in place. This proposed alternative, like the WSPA Alternative discussed above, was rejected , in the absence of any substantive analysis to support the assertions below:[5]

> *The proposed alternative assumes that the exclusive goal of the LCFS proposal is to achieve GHG emissions reductions without regard to source. If that were the case, this would be a viable alternative to the LCFS and would be assessed in this analysis. It is likely true that the estimated GHG emissions reductions appearing in the 2009 LCFS Initial Statement of Reasons ((California Air Resources Board, 2009)) could be achieved by the AB 32 Cap-and-Trade Program, along with the other programs cited by Sierra Research and Growth Energy. The LCFS proposal, however, was designed to address the carbon intensity of transportation fuels. Transportation in California was powered almost completely by petroleum fuels in 2010. Those fuels were extracted, refined, and distributed through an extensive and mature infrastructure. Transitioning California to alternative, lower-carbon fuels requires a very focused and sustained regulatory program tailored to that goal. The other regulatory schemes the alternative would rely on are comparatively "blunt instruments" less likely to yield the innovations fostered by the LCFS proposal.*

B4-66 cont.

However, CARB staff did acknowledge that:

> *The proposed alternative assumes that the exclusive goal of the LCFS proposal is to achieve GHG emissions reductions without regard to source. If that were the case, this would be a viable alternative to the LCFS and would be assessed in this analysis. It is likely true that the estimated GHG emissions reductions appearing in the 2009 LCFS Initial Statement of Reasons ((California Air Resources Board, 2009)) could be achieved by the AB 32 Cap-and-Trade Program, along with the other programs cited by Sierra Research and Growth Energy.*

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[4] See for example https://www.arb.ca.gov/msprog/aqip/aqip.htm
[5] See pages E-36 and E-37 of Appendix E of the 2015 LCFS ISOR at https://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15appe.pdf

Attachment 2

Although CARB did not specifically acknowledge the potential of the WSPA alternative to achieve the same GHG reductions as the proposed 2018 LCFS amendments, the extension of the Cap-and-Trade regulation through 2030 makes CARB's response to Growth Energy's 2015 proposal clear, that this is in fact the case.

As evidenced by the above and all of the regulatory documents prepared with respect to the 2015 and 2018 LCFS rulemakings, the alternatives analyses included in the ISOR and the EA should include a substantiated, quantitative analysis of the ability of a modified Cap-and-Trade regulation to replace the LCFS regulation while ensuring that the targeted GHG reductions are achieved at an equivalent or lower cost. Given that there is no statutory requirement for CARB to operate an LCFS program, both the EA and te ISOR should include such analyses to demonstrate the actual need for the LCFS program in light of the fact that its goals duplicate those of the Cap-and-Trade regulation with respect to reducing GHG emissions associated with transportation fuels and as noted by WSPA that required GHG emissions can be realized at much lower cost through the Cap-and-Trade regulation. B4-66 cont.

Declaration of James M. Lyons

Attachment 3

Attachment 3

CARB Staff Should Consider Alternative Fuel Specifications for E15 In Order to Facilitate Compliance with the LCFS Regulation

In 2010[1] and 2011[2], the U.S. EPA promulgated partial waivers allowing the use of E15 in 2001 and newer model-year vehicles. E15 is now available in 29 states.[3] However, at present, California has not adopted the alternative fuel specifications required to allow for the sale of E15 in the state despite the fact that CARB has long recognized that E15 can play an important part in reducing GHG emissions and ensuring that transportation fuel providers can comply with the LCFS regulation. This is the case, for example, in the ISOR for the 2009 LCFS regulation[4] where staff noted that E15, if approved by U.S. EPA, could provide additional volumes of ethanol needed for LCFS compliance. Similarly, in 2011, after U.S. EPA's approval of E15, the LCFS Advisory Panel's assessment of the potential for future compliance with the LCFS relied heavily on an assumption that E15 would be in widespread use in California by 2016.[5]

Further, as indicated in CARB's "Illustrative Compliance Scenario Calculator"[6], CARB staff currently estimates that the use of ethanol results in approximately 30% less GHG emissions than the use of a comparable amount of petroleum based gasoline feedstock based on equivalent energy content and forecasts that by 2030, GHG emissions from ethanol use will be 50% lower than from petroleum feedstocks. Given this, it is clear that allowing E15 in California will reduce GHG emissions, and result in greater volumes of LCFS credits which in turn will help to ensure and reduce the cost of LCFS compliance. E15 fuel specifications would also further diversify California's transportation fuel pool and reduce California's reliance on CARB staff's postulations regarding the availability of new supplies of renewable diesel, biodiesel, and electricity in order to achieve LCFS compliance. B4-67

While CARB has not yet moved forward to enact specifications for E15, it is clear from the U.S. EPA's action that there are no technical barriers to the use of E15 in California in 2001 and later model-year vehicles that constitute the bulk of the California vehicle fleet. It is also evident that widespread use of E15 would increase the already large of amount of LCFS being generated by ethanol[7] by another 50%.

Given the above, CARB should either move forward as quickly as possible to initiate the rulemaking process required to develop California fuel specifications for E15 or provide an analysis that shows the technical, environmental, and/or economic reasons why E15 should not be available in California to assist fuel providers in complying with the LCFS regulation.

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1 https://www.gpo.gov/fdsys/pkg/FR-2010-11-04/pdf/2010-27432.pdf
2 https://www.gpo.gov/fdsys/pkg/FR-2011-01-26/pdf/2011-1646.pdf
3 https://www.afdc.energy.gov/fuels/ethanol_e15.html
4 See pageVIII-13 of https://www.arb.ca.gov/regact/2009/lcfs09/lcfsisor1.pdf
5 https://www.arb.ca.gov/fuels/lcfs/workgroups/advisorypanel/20111208_LCFS%20program%20review%20report_final.pdf
6 https://www.arb.ca.gov/fuels/lcfs/rulemakingdocs.htm
7 See for example, page I-6 of the 2018 LCFS ISOR.

Declaration of James M. Lyons

Attachment 4

Attachment 4

Review of CARB Staff Estimates of the Emissions Impacts Associated with Biodiesel use in California

During the course of the rulemaking process that lead to the adoption of the proposed Alternative Diesel Fuel (ADF) regulation and the readopted Low Carbon Fuel Standard (LCFS) regulation in 2015 by the California Air Resources Board (CARB), Growth Energy submitted extensive comments regarding issues with the analysis of the impact of the use of blends of biodiesel and conventional diesel fuel resulting from the ADF and LCFS regulation on emissions of oxides of nitrogen (NOx) from diesel vehicles operating in the state of California. Those Growth Energy comments, which demonstrated that the CARB staff analysis was insufficient and could not be relied upon are attached to this document as Appendix A. It should be noted that these comments have been passed over but never disaffirmed, and are still applicable to the staff's 2018 analysis of this issue.

As part of the 2018 LCFS rulemaking, the ISOR states that it presents a new analysis that utilizes a "conservative analytical approach that likely overestimates LCFS attributable impacts" of the impact of "biodiesel" and "biomass-based diesel" use in California on emissions of NOx and particulate matter (PM). Just as was the case with prior documents prepared to support the 2015 rulemaking, the new CARB analysis supporting the 2018 rulemaking is again insufficient and should be revised as explained below.

Summary CARB Staff's Conclusions

B4-68

On March 6, 2018, CARB staff released the proposed LCFS regulation language, the accompanying Initial Statement of Reasons (ISOR), as well as supporting information.[1] Staff's analysis of the impact of the proposed ADF regulation on NOx and PM emissions and supporting information and assumptions are summarized in the ISOR Appendix G.

The conclusion[2] of the analysis in Appendix G regarding biodiesel impacts on NOx emissions is that:

> *...biodiesel use attributed to the LCFS would result in a potential increase in NOx emissions relative to use of conventional diesel in all years from 2019 through 2030. Even though the consumption of biodiesel in California is expected to increase over time, the NOx emissions impact is expected to decrease as the result of NOx mitigation of higher biodiesel blend levels required by the ADF regulation and the turnover to lower-NOx engines.*

This conclusion is based primarily on assumptions, and not substantial evidence in the record. Further, Appendix G considers but then dismisses a regulatory alternative that would ensure that biodiesel use in California creates no adverse environmental impacts based on economic factors alone without providing adequate data to justify that assumption.[3]

[1] See https://www.arb.ca.gov/regact/2018/lcfs18/lcfs18.htm
[2] See https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf page V-12.
[3] See https://www.arb.ca.gov/regact/2018/lcfs18/appg.pdf

Attachment 4

CARB's Assumptions

CARB's analysis of the environmental impacts associated with biodiesel and the agency's conclusions rest on the following assumptions that are unsupported by the evidence. Key among these assumptions are:

1. The use of biodiesel in so called "new technology diesel engines" (NTDEs)[4] will not result in any increase in NOx emissions because those engines are equipped with selective catalytic reduction (SCR) systems that CARB staff claim, again without support, will mitigate biodiesel related increases in engine out NOx emissions;[5]

2. Increased emissions of NOx from the use of biodiesel can be claimed to be mitigated by reductions in NOx emissions resulting from the use of renewable diesel;[6] and that

3. A requirement that all biodiesel be subject to the NOx mitigation requirements of the Alternative Diesel Fuel regulation is not cost-effective and would reduce biodiesel use in California and therefore such a requirement should be rejected.[7]

Beginning with the first assumption regarding NOx increases resulting from the use of biodiesel in NTDEs, Appendix G does not identify or reference any new publications or data that supports this assumption beyond the data of Lammert upon which CARB staff misguidedly relied during the development of the 2015 LCFS regulations as indicated by Rincon Ranch Consulting.[8]

B4-69 continues to footnotes below

Biodiesel Increases NOx emissions from NTDEs

Although CARB preciously recognized that Lammert was an outlier, Appendix G does not recognize the need to modify its findings. I understand this is because of the assertion that, unlike Lammert, the other studies in the literature were based on testing performed on retrofit engines. Recently, however, CARB staff and its contractors have published data that directly questions CARB staff's assumption that the presence of SCR systems will mitigate increased engine out NOx emissions associated with biodiesel use and that it is reasonable to rely on

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[4] These engines are defined in 2293.2(a)(18) as:
"New Technology Diesel Engine" or "NTDE" means a diesel engine that meets at least one of the following criteria:

(A) Meets 2010 ARB emission standards for on-road heavy duty diesel engines under section 1956.8.
(B) Meets Tier 4 emission standards for non-road compression ignition engines under sections 2421, 2423, 2424, 2425, 2425.1, 2426, and 2427.
(C) Is equipped with or employs a Diesel Emissions Control Strategy (DECS), verified by ARB pursuant to CCR, title 13, chapter 14 (commencing with section 2700), which uses selective catalytic reduction to control Oxides of Nitrogen (NOx).

[5] See Table 10 of https://www.arb.ca.gov/regact/2018/lcfs18/appg.pdf
[6] See Figure V-4 of https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf
[7] See pages G-8 and G-9 as well as G-88 to G-96 of https://www.arb.ca.gov/regact/2018/lcfs18/appg.pdf
[8] I understand a copy of this study is being submitted electronically concurrently with these comments.

B4-69 continued from above

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Attachment 4

Lammert to arrive at that conclusion. These studies[9,10,11,12] each involved testing on OEM production vehicles – not retrofits – and clearly demonstrate that the SCR systems that the ISOR claims will prevent increases in NOx emissions from biodiesel use in NTDEs are ineffective much of the time due to low exhaust temperatures. Table 5-10 of the reference listed in footnote 12 shows that the SCR systems of out-of-state line haul trucks are not-effective during 47% of vehicle operation and use of biodiesel in these vehicles would result in increased NOx emissions about 50% of the time despite the fact that they are equipped with NTDEs. The same table shows that SCR systems on drayage trucks used in port operations are ineffective 75% of the time and would therefore experience increases in NOx emissions due to biodiesel use during most of the time they are in operation. The references in footnotes 9 through 11 show that lack of SCR system efficiency results in actual in-use NOx emissions that are as much as 10 times higher than laboratory results because the SCR systems are ineffective and these high emissions would be further increased and exacerbated by the use of biodiesel. Again, it should be stressed that when SCR system efficiencies are low, NTDE NOx emissions will be affected by biodiesel use just like CARB staff acknowledges they are with older diesel engines.

In addition to the problems with NOx emissions being below the detection levels of the instrument making the measurement, Figures 12 and 13 of Lammert show very high SCR efficiencies throughout the course of testing. Therefore, the results presented in Lammert are not useful in assessing actual in-use NOx emissions from diesel vehicles as shown by CARB staff's own studies. Other factors that need to be considered when addressing in-use NOx emissions resulting from the use of biodiesel in addition to low exhaust temperatures that result in low SCR efficiency include performance deterioration, as well as tampering and mal-maintenance of SCR systems, which again, limit the SCR systems' effectiveness in reducing NOx emissions. These factors were overlooked by Lammert.

B4-70 cont.

In assessing the impact of biodiesel use on NOx emissions, Appendix G should have relied on all of the data that it possess regarding the operation of SCR systems on NTDEs including information regarding low SCR efficiencies during actual in-use vehicle operation, as well as with respect to deterioration, tampering and maintenance issues with SCR systems. Although Appendix G does not address all of these issues with respect to its analysis of the NOx impacts of biodiesel under the LCFS regulation, those issues were addressed by CARB staff during the development of the agency's newly released EMFAC2017 emission inventory model.[13] CARB should explain why, in light of this knowledge, the ISOR does not include a proper assessment of the impacts of biodiesel use on NOx emissions from NTDEs as part of its LCFS analysis.

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[9] *In-Use NOx Emissions from Model-Year 2010 and 2011 Heavy-Duty Diesel Engines Equipped with Aftertreatment Devices, Environ. Sci. Technol., 2013, 47 (14), pp 7892–7898*

[10] *Real-World Emissions from Modern Heavy-Duty Diesel Natural Gas, and Hybrid Diesel Trucks Operating Along Major California Freight Corridors", Emiss. Control Sci. Technol. (2016) 2:156-172.*

[11] *Evaluating In-Use SCR Performance: Older vs. Late MY Engines, presented at the 26th CRC Real World Emissions Workshop, Newport Beach, CA, March 12-16, 2016.*

[12] *Collection of Activity Data from On-Road Heavy-Duty Diesel Vehicles, Final Report (ARB Agreement No. 13-301), Prepared for CARB by CEERT, May 2017.*

[13] See pages 18-20, 25, 142-143, 147, 153-157 of https://www.arb.ca.gov/msei/downloads/emfac2017-volume-iii-technical-documentation.pdf

Attachment 4

Although there does not appear to be any rigorous analysis of the type required to quantify the impacts of biodiesel use on NOx emissions from NTDEs, it is possible to use the above referenced data CARB staff has published in combination with EMFAC2017 to generate estimates of the potential magnitudes of the impacts assuming that NOx mitigated biodiesel is not used in on-road vehicles equipped with NTDEs. Actual in-use NOx impacts would be higher when non-road NTDEs are considered. The first step in this process is to estimate the magnitude of NOx emissions occurring when the SCR system is ineffective. Based on Figures 1b through 3b of the reference in footnote 9, this range is between 50 and 90 percent and the mid-point of this range, 70 percent has been assumed here. Given the fact that when functional SCR systems reduce engine out NOx emissions by 90% or more, the fact that overall NOx emissions from NTDEs will be dominated by emissions occurring when SCR systems are ineffective is apparent – as is demonstrated by the CARB publications referenced above.

The next step is to determine the amount of NOx emissions generated by vehicles equipped with NTDEs. This was done for the years 2018, 2025, and 2030 for the South Coast and San Joaquin Valley Air Basis using CARB's newly released EMFAC2017 model.

The final step is assessing the percentage NOx increase expected from the use of biodiesel when the SCR system is ineffective. This value depends on the average biodiesel blend level assumed by CARB staff in those calendar years which can be found in CARB staff's Illustrative Compliance Scenario Calculator[14] and the values determined by CARB staff for the percentage increase in NOx emissions for older engines as the result of biodiesel use shown in Table 10 of Appendix G to the 2018 LCFS ISOR. B4-70 cont.

The results of these calculations are shown in Tables 1 and 2 below for the South Coast and San Joaquin Air Basins, respectively, using CARB's assumption that all diesel fuel sold in California will be low-saturation. As shown, potential increases in NOx emissions dwarf those associated with the significance thresholds established by the South Coast Air Quality Management District[15] and the San Joaquin Valley Air Pollution Control District.[16]

Table 1
Potential Increases in NOx Emissions from Use of Unmitigated Biodiesel in On-Road NTDEs Operating in the South Coast Air Basin

Year	NTDE NOx (tons/day)	BD in Diesel Pool (%)	Biodiesel Caused NOx Increase (%)	Biodiesel Caused NOx Increase (tons/day)
2018	36	5.3	1.2	0.3
2025	54	13.3	2.4	0.9
2030	59	13.5	2.4	1.0

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[14] Available at https://www.arb.ca.gov/fuels/lcfs/rulemakingdocs.htm .
[15] http://www.aqmd.gov/docs/default-source/ceqa/handbook/scaqmd-air-quality-significance-thresholds.pdf
[16] http://www.valleyair.org/transportation/0714-gamaqi-criteria-pollutant-thresholds-of-significance.pdf

Attachment 4

Table 2
Potential Increases in NOx Emissions from Use of Unmitigated Biodiesel in NTDEs Operating in the San Joaquin Valley Air Basin

Year	NTDE NOx (tons/day)	BD in Diesel Pool (%)	Biodiesel Caused NOx Increase (%)	Biodiesel Caused NOx Increase (tons/day)
2018	35.0	5.3	1.2	0.3
2025	49.0	13.3	2.4	0.8
2030	51.0	13.5	2.4	0.9

B4-70 cont.

Appendix G and the EA Should Not Rely upon the Claim that NOx Reductions from Use of Renewable Diesel Mitigate NOx Increases from Biodiesel

Appendix G and the EA rely upon the assumption that the use of renewable diesel will offset increased NOx emissions due to the use of biodiesel. First, there is nothing in the ADF regulation, the LCFS regulation, or the proposed amendments to both regulations that mandates the use of any volume of biodiesel in California, much less the use of the exact ratio of renewable diesel to biodiesel assumed in its emissions analysis. Similarly, nothing in the LCFS regulation mandates the use of alternative jet for the completion of solar steam projects, which are both claimed in Appendix G and the EA as other means of mitigating NOx increases associated with the use of biodiesel. Likewise, there is nothing in the regulation that would prevent or mitigate additional emissions of NOx if more biodiesel is used than if less renewable diesel is used. B4-71

Second, to the extent that there are reductions in NOx emissions from the use of renewable diesel, CARB has already formally committed to taking credit for those NOx reductions as part of a "Low-Emission Diesel" requirement of the agency's Mobile Source State Implementation Plan (SIP) Strategy.[17] As shown in Table 4 of the SIP Strategy document, CARB has claimed 8 tons per day or about 2,900 tons per year of NOx reductions for the Low-Emission Diesel requirement in 2031, with the regulatory program beginning in 2023. Comparison of this value to the NOx reductions claimed for the LCFS regulation as shown for example in Figure V-1 of the 2018 ISOR shows that the amount of NOx reductions claimed in the SIP for this measure is approximately the same as the NOx reductions CARB staff has claimed for renewable diesel use under the LCFS program. NOx reductions from renewable diesel fuel use cannot be both available to mitigate NOx increases from biodiesel use under the LCFS and the "real, quantifiable, surplus and enforceable" reductions in NOx emissions that CARB has already claimed will result from renewable diesel use as part of the already submitted SIP. Given that CARB has already made a federally enforceable commitment to use the NOx reductions from renewable diesel as part of the SIP, those reductions cannot be claimed to offset potential NOx increases from the use of biodiesel resulting from the LCFS.

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[17] See https://www.arb.ca.gov/planning/sip/2016sip/2016mobsrc.pdf

Attachment 4

CARB Could Eliminate Any Potential for Biodiesel to Increase NOx Emissions by Requiring NOx Mitigation for all Biodiesel

One of the alternatives considered by CARB to prevent the potential for increased NOx emissions is discussed only in Appendix G to the 2018 ISOR. Under this alternative, all biodiesel blends, regardless of biodiesel saturation level and season of the year, would require NOx mitigation by the LCFS to the level of conventional diesel. This is the only approach that would ensure that there are no increases in NOx emissions associated with biodiesel use in California. However, this alternative was rejected based on the following rationale:[18]

> *The future effects of requiring NOx mitigation of all biodiesel blends to the level of conventional diesel would be a likely increase in the use of additives, such as Di-tertbutyl peroxide or renewable diesel, to reduce NOx emissions associated with biodiesel use. This would increase the cost of biodiesel, which is currently one of the cheapest compliance options for the LCFS. The increased cost of biodiesel would likely reduce the incentive for its use, leading to a likely decrease in biodiesel consumption in California relative to projected levels for the project following the adoption of the Proposed Amendments. Because of this, greater quantities of other, more expensive fuels, including renewable diesel, would be necessary to replace credits that could otherwise be generated by biodiesel. Therefore, this alternative would make it more difficult and expensive to generate the average carbon intensity reductions and GHG benefits associated with the project following the adoption of the Proposed Amendments.*

B4-72

Neither the ISOR nor any of its appendices present any quantification of any increased costs for biodiesel or any analysis that shows that biodiesel use would in fact be decreased. As such, the ISOR and Appendix G should be revised to present more than opinion to reject this regulatory alternative, particularly given that this conclusion is contrary to documents published by CARB.

First, with respect to the economic feasibility of mitigating NOx emissions increases associated with biodiesel use, CARB has already approved four alternative formulations for NOx mitigated biodiesel blends[19,20,21,22] a fact that demonstrates that they are economically viable. Second, although Appendix G and the EA provide no analysis on the cost-effectiveness of NOx mitigated biodiesel, CARB has recently published data regarding the expected cost-effectiveness[23] ratios of projects that will be funded using money from the Volkswagen Environmental Mitigation Trust it received as part of the settlement of the recent Volkswagen scandal, which are summarized in Table 3. As shown, with respect to these mitigation funds, it appears CARB contends mitigation of up to $350,000 per ton of NOx emissions eliminated is reasonable.

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[18] See page G95 of https://www.arb.ca.gov/regact/2018/lcfs18/appg.pdf
[19] https://www.arb.ca.gov/fuels/diesel/altdiesel/20170720_NBB_EO.pdf
[20] https://www.arb.ca.gov/fuels/diesel/altdiesel/20180118_REG_EO_ADF02.pdf
[21] https://www.arb.ca.gov/fuels/diesel/altdiesel/20180126_CF_EO.pdf
[22] https://www.arb.ca.gov/fuels/diesel/altdiesel/20180222_TTI_EO.pdf
[23] https://www.arb.ca.gov/msprog/vw_info/vsi/vw-mititrust/meetings/021618_discussiondoc.pdf

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Attachment 4

The ISOR should also be augmented to include a quantitative analysis of the costs and benefits of requiring NOx mitigation for all biodiesel blends that demonstrates that the NOx reductions that would be achieved are not cost-effective relative to other emission control strategies CARB is pursuing in order to justify its rejection of this regulatory alternative.

B4-72 cont.

Table 3
Expected Cost-Effectiveness Ratios for NOx Reductions Achieved by Projects Funded Through the Volkswagen Environmental Mitigation Trust

Project Type	Cost-Effectiveness ($/ton of NOx emissions eliminated)	
	Low	High
Transit, School, and Shuttle Buses	30,000	180,000
Class 8 Freight, Port and Drayage Trucks	80,000	95,000
Zero Emission Freight/Marine	130,000	350,000
Combustion Freight/Marine	5,000	30,000

CARB's Proposal to Mitigate Past NOx Emission Increases Associated with Biodiesel

In addition to rejecting requirements for NOx mitigation on all biodiesel blends, Appendix G to the 2018 ISOR[24] also proposes to attempt to mitigate past NOx emissions by providing funding to unspecified local air quality districts to implement NOx mitigation programs like those funded by the Carl Moyer program. However, this discussion does not specify the amount NOx emissions that will be mitigated, the source of the funding, specifics regarding the types of projects that will be funded, how the agency will ensure that funding is actually made available, or how the projects will actually be implemented. B4-73

[24] See pages G55-57.

Declaration of James M. Lyons

Attachment 5

CARB Can Formulate Mitigation Strategies to Address Adverse Impacts on California Air Quality from New or Modified Transportation Fuel Production Facilities Created by the LCFS

The draft Environmental Analysis ("EA") for the 2018 LCFS Amendments (Appendix D to the ISOR)[1] indicates that new or modified transportation fuel production facilities will be required in California to provide the low CI fuels needed to meet the demand caused by the LCFS. The EA states that those new or modified facilities in turn will create potentially significant and unavoidable impacts on air quality. However, the EA explains[2] that, despite the causal effect of the LCFS regulation in creating these impacts, CARB does not have the authority to require mitigation of such impacts:

CARB does not have the authority to require implementation of mitigation related to operation of new or modified facilities that would be approved by local jurisdictions. The ability to require such measures is within the purview of jurisdictions with local or State land use approval and/or permitting authority. New or modified facilities in California would likely qualify as a "project" under CEQA, because they would generally need a discretionary public agency approval and could affect the physical environment. The jurisdiction with primary approval authority over a proposed action is the Lead Agency, which is required to review the proposed action for compliance with CEQA. Project-specific impacts and mitigation would be identified during the environmental review by agencies with project-approval authority. B4-74

> *Because the authority to determine project-level impacts and required project-level mitigation lies with land use and/or permitting agencies for individual projects, and the programmatic level of analysis associated with this EA does not attempt to address project-specific details of mitigation, there is inherent uncertainty in the degree of mitigation that may ultimately be implemented to reduce potentially significant impacts. With mitigation, operational emissions could still exceed local air district threshold levels of significance, though this is not likely.*
>
> *Consequently, while CARB does not believe significant localized increases are likely and anticipates overall beneficial long-term operational impacts and if they were to exist impacts should be reduced to a less-than-significant level by land use and/or permitting agency conditions of approval, this EA takes the conservative approach in its postmitigation significance conclusion and discloses, for CEQA compliance purposes, that long-term operational-related air quality impacts resulting from the operation of new or modified facilities associated with the Proposed Amendments would be potentially significant and unavoidable.*

[1] https://www.arb.ca.gov/regact/2018/lcfs18/appd.pdf
[2] See pages 69, 70, 131 and others in https://www.arb.ca.gov/regact/2018/lcfs18/appd.pdf

Further, CARB's analysis of emission impacts of modified and new transportation fuel production facilities[3] is performed only on an aggregated basis[4] relative to the expected increases in the use of specific types of low CI fuels in California over time. It appears that the methodology in the EA for estimating emissions from modified and new transportation fuel production facilities for the 2018 LCFS amendments differs from that used for assessing the impacts of the 2015 LCFS amendments,[5] as does the presentation of emissions data from specific existing and potential California production facilities.

The importance of the fact that the EA does not assess environmental impacts from potential modified or new transportation fuel production facilities located in California in its assessment of the 2018 LCFS amendments can be seen in information included in the 2015 LCFS analysis. For example, in the 2015 LCFS analysis, the ISOR reported that one potential cellulosic ethanol facility considered for location in northern California could emit 3.9 tons of NOx per day or about 1,400 tons per year, which is well in excess of any local California air quality district's threshold for a significant impact and would require extensive mitigation. In addition, the NOx emission factor for this potential facility was derived directly from data for a biomass plant as shown in Table IV-15 of the 2015 ISOR and is over 120 times greater than the NOx emission factor that CARB staff used for the 2018 LCFS analysis which is presented in Table F-3 of Appendix F to the 2018 ISOR. There is no clarification presented by CARB staff explaining this discrepancy. Further, it does not appear that the EA includes the same kind of health risk assessment of potential California biofuel facilities that was presented in the 2015 LCFS ISOR as part of the 2018 LCFS analysis. B4-74 cont.

Overall, the EA's analysis of the potential impacts of modified and new transportation fuel production facilities in California driven by the LCFS regulation is incomplete, and a much more detailed analysis should be performed.

In addition, the EA does not identity, present, and analyze obvious mitigation requirements that could be incorporated into the LCFS regulation. For example, in approving the fuel production pathway CI values for modified and new California facilities, CARB could modify the LCFS regulation to withhold approval unless all significant environmental impacts of a facility were adequately mitigated. This could include requirements that project proponents and operators engage in Voluntary Emission Reduction Agreements (VERAs)[6] like those that are currently being required in the San Joaquin Valley.[7] Another example, of what CARB could do is, provided that it is adequately described and documented, expand the funding program described in Appendix G to the 2018 ISOR[8], intended to mitigate past NOx emissions associated with biodiesel use by providing funding to local air quality districts to implement programs like those funded by the Carl Moyer program.

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[3] https://www.arb.ca.gov/regact/2018/lcfs18/appf.pdf
[4] See page 69 of https://www.arb.ca.gov/regact/2018/lcfs18/appd.pdf
[5] See section IV of the 2015 LCFS ISOR at https://www.arb.ca.gov/regact/2015/lcfs2015/lcfs15isor.pdf
[6] http://www.valleyair.org/ceqaconnected/aqimeasures.aspx
[7] http://www.valleyair.org/isr/Documents/2017-ISR-Annual-Report.pdf
[8] See pages G55-57.

APPENDIX "B"

REVIEW OF THE ENERGY EFFICIENCY (EER) RATIO UTILIZED IN THE LCFS REGULATIONS

Prepared for:

Growth Energy

Prepared by:

H-D Systems
Washington, DC

April 23, 2018

1. INTRODUCTION

The California Low Carbon Fuels Standard (LCFS) incorporates the differences in the energy efficiency of alternative fuel vehicles relative to similar conventionally (gasoline and diesel) fueled vehicles by using an Energy Economy Ratio (EER) to determine the carbon intensity of alternative fuel vehicles for purposes of developing carbon credits. The EER is the ratio of energy use by the alternative fuel vehicle to the energy used by a conventional vehicle per unit travel distance. Since the performance characteristics of alternative fuel vehicles are sometimes quite different from those of conventional vehicles, the concept of EER incorporates a subjective element in the identification of "similar" vehicles to develop an EER. In addition, the response of alternative fuel vehicles to various duty cycles of operation and to changes in ambient temperature can differ from the response of conventional vehicles, and the EER is a function of both the duty cycle and ambient temperature under such conditions.

The ARB has documented the EER values for several alternative fuel vehicle types in Appendix H of the 2018 Initial Statement of Reasons for amendments to the LCFS. This report examines the EER values in Appendix H of the ISOR to assess its reasonableness using both an engineering analysis and an assessment of the similarity of vehicle types and tests used to generate the data underlying the EER. In addition, the EER values for cars and light trucks developed in the 2009 ISOR when the LCFS was first introduced are also reexamined in this report.

The report begins with an examination of fundamental engineering-based analysis of diesel and gasoline engine efficiency and their comparison to electric motor efficiency. It also examines vehicle power consumption especially for accessory drives which are often not utilized during tests of emissions or fuel economy. The discussion also covers the effects of driving cycles and varying ambient temperatures and how these factors affect energy efficiency. Following this general discussion, a critique of the EER values published in the ISOR for each vehicle type is provided.

2. ENGINEERING CONSIDERATIONS IN DEVELOPING THE EER

Our examination of the EER values developed in Appendix H showed that the methodology adopted by ARB to develop the EER ignored some aspects of engine efficiency trends with load and speed, and also did not consider the differences between dynamometer test procedure and real-world operation. In addition, the effects of ambient temperature were not discussed or included in the computation of EER. Chassis dynamometer ("dyno") tests are conducted with all accessories off and at an ambient temperature of 70 to 75 F, which are conditions where EER for electric vehicles may be the highest. Because these conditions may be experienced for only B4-75

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short periods of time in much of California, EER values developed from dyno test data do not reflect real world conditions for much of the time such vehicles will be operating. The discussion below on engineering considerations provides a foundation for the critique of specific EER values in the following sections. B4-75 cont.

Conventional Gasoline and Diesel engines

Gasoline and diesel vehicles are the baseline for comparison for developing the EER values of alternative fuel vehicles. In modern vehicles the spark ignition (gasoline) engine has a peak efficiency of 35 to 36 percent but some more recent designs being introduced in cars and light trucks have efficiencies approaching 40%. Light duty diesels have a peak efficiency of about 41 to 42 percent but do not have near term prospects for improving significantly. B4-75a

In a heavy-duty vehicle, diesel engines are more efficient with peak efficiency of 43 to 44%. However, the peak efficiencies are realized at high loads and the efficiency of both diesel and gasoline engines decline at low loads and is zero at idle by definition. The diesel's efficiency declines less than that of a s.i. engine with load reduction so that its relative efficiency over a gasoline engine improves at light load.

CNG and Propane Engines

Natural gas and propane are used primarily in spark ignition (s.i.) engines, but the type of s.i. engine differs between those used in light and light heavy vehicles up to about 14,000 lb. GVW. In these lighter vehicles, propane and natural gas engines are simple conversions of gasoline engines, with only the addition of a different fuel system. Efficiency is generally unaffected, implying a EER of 1.0. However, the tanks used for propane and CNG fuel are quite heavy and a CNG tank capable of providing over 200 miles range can weigh over 250 lbs. which is a significant weight increase. On a 4000 lb. gasoline vehicle, the addition of CNG tanks can cause fuel economy to decrease by 3 to 5 percent so that the EER will decline to 0.95 to 0.97. The lower power of the CNG engine further compromises the EER due to axle ratio and gear shift adjustments that must be made to restore performance and the net EER can decline to 0.9. B4-75b

CNG spark ignition engines used in heavy trucks over 18,000 lb. GVW typically use a modified diesel engine so that they are highly turbocharged and offer better efficiency than a simple gasoline engine conversion but are still subject to the same trends with load and speed. While on a highly loaded duty cycle, the EER of a CNG can be as high as 0.9 relative to a diesel, this value declines due to the diesel's improved efficiency at lighter loads relative to an s.i. engine. In addition, the weight of the fuel tanks for the CNG fuel also reduces the vehicle efficiency at similar payload.

Electric Drivetrain and Battery Losses

Comparison of electric drivetrain efficiency to gasoline or diesel efficiency is more difficult due to the completely different efficiency characteristics of an electric motor relative to an internal combustion engine. Typically, an electric motor is most efficient at mid load/ low speed operation but becomes less efficient at high loads and very light loads. At "idle", and electric motor uses very little power (mostly in the controller). A typical electric motor/ controller's peak efficiency can be as high as 92 to 93% but the average efficiency in most light vehicular duty cycles is in the 80 to 85% range. In addition, the battery has internal energy loss during both charging and releasing energy so that the battery plus drivetrain efficiency is in the 75 to 80% range. Unlike the trend for internal combustion engines, system efficiency declines with higher loads so that on heavy trucks, the net efficiency on a highly loaded cycle can be significantly lower than the net efficiency for light vehicles. B4-75c

The weight of the battery is also an important consideration in the determining the vehicle EER. In light vehicles with a range of 150 to 250 miles, the battery system weight ranges from 500 to 1000 lbs. while on a heavy truck, battery weight is 15% to 20% of the gross vehicle weight if the range is 150 to 200 miles. This has very significant impact on the EER of the vehicle and the EER can only be defined in the context of specific vehicle range and battery weight.

Impact of Accessory Loads

As noted, accessory loads are not switched on during dynamometer testing and their impact on the EER varies by vehicle type. Incorporation of accessory loads increases the load on the engine, or in the case of an EV, the battery. Increasing the load on an engine makes it more efficient while increased loads on the battery make it less efficient so that this affects the EER even if the accessory loads are identical. Accessory loads are particularly important in buses where the HVAC system accounts for as much as 40% of total fuel use in a transit bus in summer. These loads have a more modest effect on light duty vehicle fuel consumption. B4-75d

In winter, diesel and gasoline engines use waste heat for providing passenger cabin heating but this is not possible in an EV where there is very little waste heat available. As a result, battery energy must be used and the resulting energy consumption substantially affects the EER. The reduction in EER can be very significant as many EVs use resistance heating for low cost, but this very inefficient.

Impact of Ambient Temperature

Ambient temperature affects the energy consumption in two ways – first by changing the energy consumption of the drivetrain and second, by requiring the use of air-conditioning or B4-75e

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heating. As noted, these factors are not reflected in the standard dyno tests which are conducted at ambient temperatures of 70° to 75° F without the HVAC system being on.

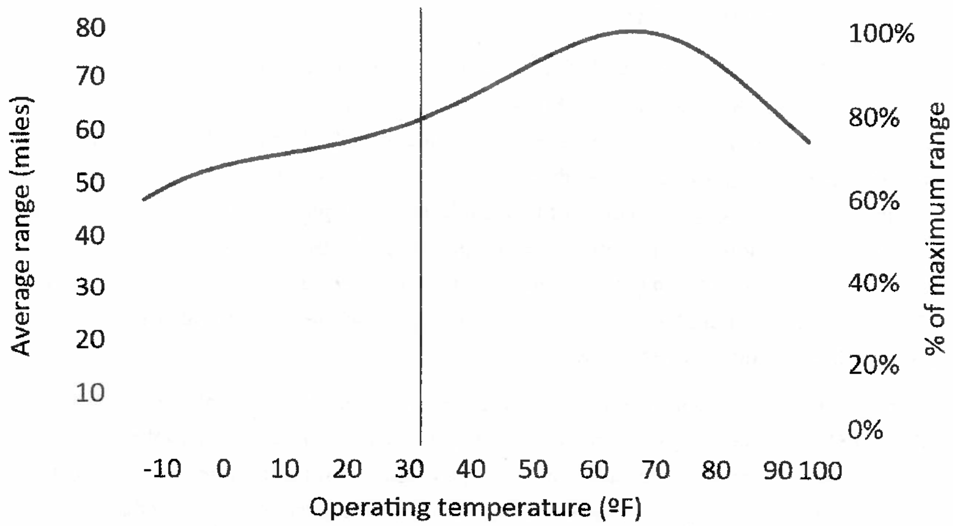

Figure 1: Average range of the Nissan Leaf as a function of Ambient Temperature[1]

At cold ambient temperatures below 10° F, fuel economy of internal combustion engines is decreased significantly due to the cold start and the energy needed to heat up the engine and transmission to operating temperature but the penalty is largely restricted to the warm-up period. Hence, the penalty averaged over a long trip becomes small. On an EV, battery internal losses and self-discharge increase with decreasing ambient temperatures and the energy loss is internal to the battery. In addition, the requirement for heating the cabin further deteriorates the vehicle EER. The combined loss results in loss of range, which is significant. An example of the loss of range with changes in ambient temperature for the Nissan Leaf EV is shown in Figure 1. As can be seen from the figure, battery range is maximum at 70° F (the typical dyno test temperature) and drops at both higher and lower temperature. At both 100° F and at 32° F, the range is 78% of the range at 70° F. Internal combustion engine powered cars have similar losses in fuel economy in summer but lower losses in winter, so that the reduction in EER of electric personal vehicles is potentially modest. However, in buses and commercial vehicles, the reduction in EER at colder temperatures may be quite large due to the high heating and ventilation load. We anticipate that the EER of electric vehicles could decline by 10 to 15% for

B4-75e cont.

1 Data from Fleet Carma as reported on the Union of Concerned Scientists website

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passenger cars and cargo trucks, and by 25 to 30% for buses in winter (50° F) and summer (>90° F) relative to the EER estimated from tests conducted at 70° F with the accessories shut off. B4-75e cont.

3. LIGHT DUTY CARS AND TRUCKS

In the 2009 LCFS, the EER of 1.0 for CNG vehicles relative to gasoline vehicles used in light-duty and medium duty applications and an EER of 3.0 for battery electric and plug-in hybrid electric light vehicles operating on electric power were developed by ARB. The LCFS accounted for the potential increases in gasoline engine efficiency by increasing the average fuel economy of light duty vehicles from 29 mpg by 30 percent to account for the impact of fuel economy standards. However, the LCFS does not account for the temperature effects which could potentially reduce the EER by 10 to 15% as noted in the previous section. The EPA tests are performed at 70° F without accessories, so that a more comprehensive EER estimate that includes winter and summer effects requires further study. B4-76

Currently, there are no EV light trucks in the market except the Tesla Model X, but we anticipate SUV and passenger van models are likely to have EER values close to those for cars. However, battery electric cargo vans and pickups will have significant reduction in payload capability compared to gasoline models of similar size and an adjustment methodology to account for the payload capability is required to develop EER values for such vehicles (several small electric cargo vans are expected to be introduced in 2019/2020).

The 2009 ISOR also estimates an EER of 2.3 for the hydrogen fuel cell vehicle. In 2018, there are three fuel cell vehicles in the market. Comparisons of the unadjusted EPA test fuel economy to their equivalent gasoline counterparts' fuel economy are shown in the table below

FCV Model	EPA FE (gasoline equivalent)	Gasoline model	EPA FE mpg	EER
Honda Clarity	98.0	Honda Civic 5-dr	47.29	2.07
Hyundai Tuscon	72.5	Tuscon FWD	36.10	2.01
Toyota Mirai	97.9	Toyota Camry	46.84	2.09

B4-78

The data shows remarkably consistent values with an average EER of 2.06, which is lower than the 2.3 value estimated by ARB. It is not clear how the fuel economy of the fuel cell deteriorates in hot and cold weather and this may change the estimated EER value (at 70 F without accessory loads) of 2.06 further. A lower value of EER consistent with the data is recommended for use.

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Finally, the ISOR estimates a CNG vehicle EER of 1.0 which does not account for the increased weight of the CNG fuel tanks and reduced engine power. The now discontinued Civic CNG model was rated 41.15 mpg for the unadjusted EPA test value in MY2015, while the gasoline Civic model with the same 1.8L engine was rated at 44.78 mpg. This shows an EER of 0.92 which may be better than the EER of light duty CNG aftermarket conversions, which are the only light duty CNG vehicles now available. We would suggest an EER value of 0.9 as appropriate for aftermarket conversions. B4-78 cont.

4. EER for LPG trucks and buses

The 2018 ISOR contains an extensive discussion of LPG bus fuel economy and the EER values relative to diesel and gasoline buses based on the testing done at the Altoona Bus Testing Center. The tests include dynamometer tests using the Manhattan cycle (6.8 mph average speed), the Orange county cycle (12.0 mph) and the Urban Dynamometer Driving Schedule (18.9 mph). Tests were also conducted on the test track using cycles labelled CBD (12.8 mph) Arterial (27 mph) and Commuter (38 mph) test cycles. In both the dyno and track tests, the HVAC system was turned off. In addition, the test cycles used for the track tests do not resemble normal driving in that the cycles consist of a simple pattern of steady accelerations cruise at constant speed, and steady deceleration to idle. B4-80

Hence, the loads on the test track cycle do not resemble those for the dyno tests, and there is significant reason to doubt test track results between different engine types (spark ignition vs. diesel) would yield EER values consistent with real world values. This is particularly true given that the track data also appeared to contain more errors than the dyno data. For example, the fuel economy measured on the Commuter cycle (which is essentially a constant speed cycle at 40 mph with 2 stops) was worse than the fuel economy measured on the UDDS cycles (with numerous stop-and-go events and a speed of 18.9 mph) on the dyno for many of the vehicles in the ARB database. These data would contradict the fact that fuel economy of conventional vehicles is typically highest at 40 to 50 mph constant speed conditions.

Figure 2 taken from the ISOR shows the EER values computed for three different LPG vs. diesel vehicle pairs labelled as "trolley", "upfit" and "school bus". The EER trend for the trolley with increased cycle average speed shows a different trend than those for the other two types, where the propane vehicle EER decreases with increasing speed.

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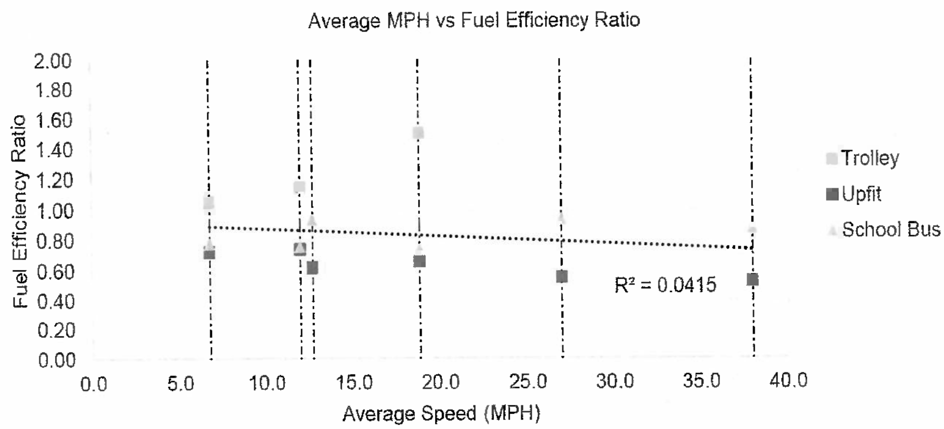

Figure 2: EER of Propane Buses relative to Diesel Buses

B4-80 cont.

An examination of the data showed that mixing the track and dyno results could mask the real trends in the EER, and that the diesel trolley bus chosen for comparison had unusual fuel economy trends on the dyno compared to the trends for other vehicles. If the other trolley excluded by ARB in its analysis (for its test weight being about 20% heavier) is chosen for reference and the EER discounted by 20% (as a 1% increase in weight decreases fuel economy by approximately 1% in slow speed stop and go cycles), a more comparable set of figures emerge as shown below:

Test Type	Cycle	Trolley	Upfit	Bus
Dyno	Manhattan	0.83	0.72	0.78
	Orange	0.79	0.74	0.76
	UDDS	0.70	0.66	0.74
Track	CBD	0.90	0.62	0.93
	Arterial	0.93	0.55	0.93
	Commuter	1.02	0.52	0.87

While the data still shows some scatter, the low speed cycle data on the dyno suggest a propane bus EER of 0.74 for urban cycles. The high-speed arterial and commuter cycle data from the test track show a significant discrepancy for the "upfit" vehicles and the data on the

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diesel upfit vehicles on the test track was difficult to reconcile against their performance on the dyno tests. One upfit diesel vehicle showed higher mpg on the dyno UDDS cycle than on the 38 mph commuter cycle which has only two stops and extensive cruise at 40 mph, and this appears unlikely in real world driving. Ignoring the upfit EER results would suggest an EER of 0.9 to 0.95 for higher speeds. The higher EER at higher speeds is also consistent with the narrowing efficiency differential between s.i. engines and diesel engines at higher speeds and loads. B4-80 cont.

The ARB has also estimated an EER of 1.0 for a propane bus relative a gasoline bus at urban speeds. Note that this is quite consistent with an EER of 0.74 for a propane to diesel bus comparison as the diesel is known to be 25 to 30 percent more efficient relative a gasoline engine at urban speeds.

5. **EER for Transport Refrigeration Units**

ARB acknowledges that the data from Transport Refrigeration units (TRU) is sparse and has estimated the EER from a single fleet using a sample of 4 diesel TRU units. Appendix H mentions that electricity use was obtained from one of the units but it is unclear if diesel and electricity use were obtained from the same unit. The EER developed uses the four diesel unit data and the single data point for electricity consumption. However, the diesel data showed vary large variance in the TRU diesel fuel consumption with one unit at 0.40 gal/hr, the second at 0.81 gal/hr, the third at 1.31 gal/hr and the fourth at 1.57 gal/hr, which is a 392% variance between units ostensibly of the same size. This would suggest that the refrigeration loads were very different between the units, and if electricity consumption was measured with diesel consumption on the same unit, it would be important to use a consistent set of data to derive the EER value. It is also unclear why the median electricity consumption value rather than the mean was selected to derive the EER. B4-81

The computed EER value of 3.4 may be a reasonable or somewhat optimistic value, as the efficiency of a diesel engine in cyclic operation is typically 25 to 30 percent, while the efficiency of an electric motor/ controller driving the compressor of the TRU can be in the 80% to 85% range which would suggest EER values in the 2.7 to 3.4 range.

6. **EER for Electric Motorcycles**

ARB has derived the EER for electric motorcycles based on a sample of electric motorcycles tested by the EPA on the UDDS cycle on the dyno, and comparing the energy use to gasoline motorcycles with similar rated power. However, the UDDS is a very slow speed cycle with gentle accelerations and multiple stops. Motorcycles have very high power-to-weight ratios relative to cars and trucks, and the UDDS is not likely to represent the driving cycle for most motorcycle owners. (ARB should also distinguish between on-road motorcycles versus B4-82

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children's electric motorcycles which do not provide any energy benefit) In addition, gasoline motorcycle engines are designed for high specific output and are quite inefficient at the low speeds in the UDDS. The EER values of 8 to 10 found in the sample comparison are not applicable, and ARB has recognized this and suggested an EER of 4.4. However, no basis is provided for the staff multiplying the UDDS value of EER by 0.5 to obtain the 4.4 value. One option may be to use the US06 cycle for testing both electric and gasoline motorcycles as this would represent a more aggressive and well-developed cycle but not derived from motorcycle specific driving patterns. Otherwise, driving cycle data from instrumented motorcycles will need to be collected and a test procedure developed to characterize motorcycle EER.

B4-82 continued from previous page, continues to footnote below

Electric motorcycle efficiency can also be deduced from the battery capacity and claimed range from the motorcycle manufacturer websites. As an example, Zero motorcycles claims a city/highway combined range of 108 miles with a 13 kWh battery and a range of 138 miles with a 16.6 kWh battery for its Zero S model. Assuming that 90% of battery capacity is available for use, the energy consumption is 0.11 kWh/mi at the battery and 0.13 kWh/mi at the plug assuming battery charger efficiency and battery storage loss combined of 85%. The motorcycle has a motor rated at 60HP, which is comparable to gasoline motorcycles with a 650cc to 750cc engine. Data from the motorcycle fuel economy guide[2] shows ratings of about 60 to 70 mpg for many such vehicles (although there is a lot of variability) which indicates a potential EER of about 3.5. A more comprehensive analysis is required to establish a more accurate EER but we anticipate that EER values of about 3.5 may be more realistic than the 4.4 value suggested by ARB as we expect similar EER values to those derived for electric cars.

7. EER for Electric trucks and buses

ARB has derived data for electric bus EER values from tests conducted at the Altoona bus center, and the data suffers from many of the same issues raised for the propane bus EER analysis. As noted, the HVAC system is turned off during the tests. The Altoona bus tests showed a 5.4 EER for an electric bus relative to a diesel bus over the CBD cycle which has an average speed of 12.7 mph. As noted in Section 4, the track tests do not use "realistic" cycles and even comparisons between similar vehicles of different fuel types can be erroneous if the powertrain efficiency responds differentially to load.

B4-83 continues to footnote below and next page

A more valid comparison is obtained from the NREL study[3] comparing electric buses to CNG buses in the San Gabriel and Pomona Valley region where data was collected from in-service buses where the HVAC was functioning. This study is referenced by ARB but oddly, it shows

[2] www.totalmotorcycle.com/MotorcycleFuelEconomyGuide/2016b

B4-82 continued from above

[3] NREL, Foothill Transit Battery Electric Bus Demonstration Results, Technical Report NREL/TP-5400-65274, January 2016

B4-83 continued from above

data attributed to the NREL study that differ in fuel consumption by a factor of 2 for CNG buses to what is shown in the NREL study.

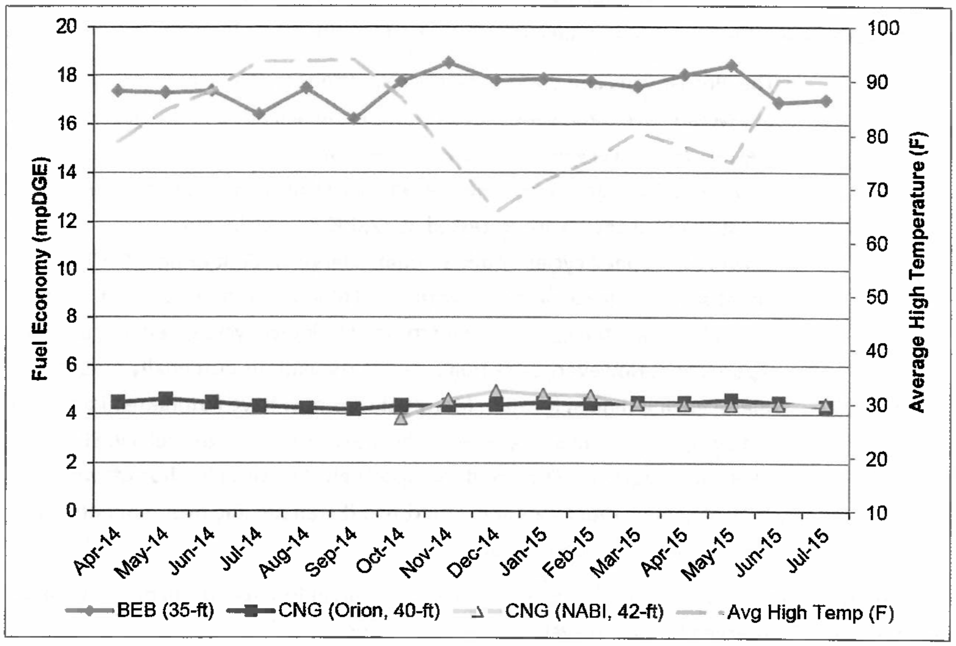

Figure 3: Fuel economy of Electric buses and CNG buses operated by Foothills Transit

The CNG bus fuel economy is shown as 2.1 mpg (diesel equivalent) in Appendix H but the NREL report lists the CNG bus fuel economy as 4.51 mpg diesel equivalent. The electric bus fuel economy is reported in both studies as 17.5 mpg so that the computed EER differs by more than a factor of 2. Our computation of EER for the electric bus from NREL data shows an EER of 3.29 relative to a diesel bus assuming that the diesel is 15% more efficient than a CNG bus. The NREL report indicates that average speed was 8.42 mph with over 50% of time at idle as evidenced by the average speed excluding idle time of 17.66 mph. Figure 3 shows the seasonal variations in fuel economy which are small as the valley has a mild climate but the dip in electric bus efficiency is significant during the warmer months and the electric bus efficiency dips as low as 16 mpg while the CNG bus efficiency declines to 4.1 mpg The EER also does not account for the fact that the CNG buses are larger than the electric buses (40 to 42 ft. long vs. 35 ft for the electric bus). At more extreme climates and especially at colder temperatures, we anticipate that the EER should be close to 3.

B4-83 cont.

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Results for the Drayage truck and the parcel delivery van are based on comparisons of more similar vehicles EV and diesel tested on the dynamometer. The issue of HVAC use is till pertinent but the energy consumption by the system on a truck is a smaller factor than on a bus. However, two other significant issues not considered by ARB affect the EER

- The electric vans and drayage trucks have the same GVW as the diesel trucks but would have significantly lower payload capacity due to the battery weight. The parcel vans may be volume constrained rather than load constrained in many cases. The drayage trucks however were obviously load constrained as they were all tested at 72,000 lb. GVW.
- On very low speed cycles under 15 mph, a large amount of time (>50%) is spent at idle. Since a diesel consumes fuel at idle but the EV consumes very little electricity, the EER should increase with lower cycle speed as shown in Appendix H. However, California anti-idle regulations potentially reduce diesel engine time in real life. Many vehicles now have automated idle shut-off after 1 minute of idling. Hence, the steep rise in electric vehicle EER is likely inaccurate for more modern diesel vehicles with idle shut-off which may become a requirement in California. (Extended idle over 5 minutes is already banned in California).

B4-83 cont.

Based on these factors, we expect that Electric truck EER even at low speed will be in the same range of 3 to 3.5 observed for electric vehicles of other types.

8. Summary and Conclusions

A review of the energy efficiency ratios for alternative fuel vehicles show the following results

- The EER value of 3.0 for electric light duty vehicles relative to gasoline vehicles may be appropriate for mild weather but is likely to be lower at more extreme ambient temperature
- The EER for Fuel cell light duty vehicles appears to be overstated based on the actual measured fuel economy data for the three fuel cell vehicles available commercially in 2018

B4-85

- The EER values for propane buses derived from Altoona Bus Testing Center data rely on tests that do not resemble real world use. An EER of 0.74 may be appropriate for propane buses but this needs confirmation on tests with the bus HVAC system operating normally.

B4-87

- The EER for Transport Refrigeration Units is derived from a small and excessively variable set of data. It is unclear if the comparison between

B4-88

electricity consumption and diesel consumption is based on the same duty cycle. B4-88 cont.

- The EER for electric motorcycles appears to have been derived arbitrarily. Data from motorcycle websites suggest lower values than those developed by ARB but more research is required. B4-89
- The EER for electric buses operating at urban speeds appears to be significantly overstated and appears to partly based on a misreading of NREL data.
- The EER for commercial electric trucks compares energy efficiency at the same gross weight which ignores the loss of payload due to the weight of the battery (which can be very significant). In addition, diesel engines operating at very low speed cycles which involve extensive idle will have significant efficiency improvement with idle shutoff, a feature that will have significant market penetration due to EPA GHG regulations on trucks. B4-90

EER Summary

Vehicle Type	EER recommended by ARB	Suggested Correction	
Battery Electric Cars (LDV)	3.0	Could be reduced by 10 to 15% in summer and winter	B4-92
Battery Electric Light Duty Trucks (LDT)	3.0	As above, plus payload reduction in cargo trucks	
Hydrogen Fuel Cell LDV	2.3	About 2.0, weather effects unknown	
CNG LDV/LDT	1.0	0.9 for aftermarket conversions	
LPG Bus	0.9	0.74 at urban speeds (<20 mph)	B4-96
Electric TRU	3.4	ARB data too variable for conclusion	B4-97
Electric Motorcycles	4.4	Probably closer to 3.5, need data	B4-98
Electric Bus	4.8 at urban speed	About 3 as an all-season average	B4-99
Parcel and Drayage Trucks	4 to 5.5	Payload loss, seasonal effects and diesel idle shutoff not accounted for.	

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Curriculum Vitae

For

K.G. Duleep

K.G. Duleep

President, H-D Systems

EDUCATION

M.B.A., Finance, Wharton School, University of Pennsylvania, Philadelphia, PA, 1989

Doctoral Candidate, Aerospace Engineering – Combustion, University of Michigan, Ann Arbor, MI, 1976

M.S., Aerospace Engineering/Computer Information and Control Engineering, University of Michigan, Ann Arbor, MI, 1975

Bachelor of Technology, Aerospace Engineering, Indian Institute of Technology, Madras, India 1972

EXPERIENCE OVERVIEW

K.G. Duleep is President of H-D Systems, a new consulting firm which is a spin-off of the EEA automotive technology group, in the Washington, DC metropolitan area. His extensive work on vehicle energy use, cost and performance of fuels and engine technology and manufacturing costs have been widely cited around the world. Through his work, he meets periodically with the technical staffs of most of the world's largest auto-manufacturers to discuss new technology and has obtained key insights on vehicle development through this process. He is well known for his work on vehicle fuel economy technology and his CAFE forecasts under alternative scenarios have been the basis for many regulatory and policy discussions in Congress. In 2008/9, he directed analyses as a support contractor to the National Academy of Sciences Committee on Fuel Economy Standards, and he is currently involved in the new CAFE standards for the post-2016 time frame. He has also performed studies on life cycle energy use and the energy use in vehicle manufacturing. He was the developer of the fuel economy forecasting algorithm embedded in NEMS, which he and his group has updated periodically.

PROJECT EXPERIENCE

Fuel Economy Modeling and Forecasting, EIA and CEC, 1990 –Present. Developed detailed forecasting models of light and heavy vehicle fuel economy that are modules within the NEMS model and the CALCARS models. Models were periodically updated by Mr. Duleep over the last 20 years.

Automotive Technology Cost Analysis, Department of Energy, ongoing. Direct multi-year task order contract with DOE'S Policy Office to evaluate costs and benefits of new automotive technologies. Also serve as technical lead on advanced engine technology analysis. Coordinate efforts of two major subcontractors. Most recent project in 2014-15 covered engine technology potential from use of 98 octane E25 (25% ethanol) blends.

Technology Planning, U.S. Oil Refiners, Japanese Auto manufacturers, 1996–Present. Provides technology planning and emissions compliance support to oil refiners and import auto manufacturers. The work involves detailed assessment of new technology for vehicles and estimation of their impact on vehicle fuel economy, cost, drivability and reliability. Forecast of technology penetration in different markets and segments of the fleet are also part of the services provided.

Alternative Fuels Outlook, Califoria Energy Commission. Led the study of alternative fuel vehicles as a means of reaching California's GHG reduction goals. Reported on the current state of vehicles and forecasted the economic viability of alternative fuels in the state considering potential roadblocks such as higher costs and increased weight. Estimated the required capital requirements for any incremental infrastructure that may be necessary. Provided strategic recommendations on investment priorities and mechanisms to accelerate commercialization of alternative fuels and technologies.

Analaysis of Fuel Cell/ Hydrogen Power in Non-Automotive Markets, US DOE, 2009-2010. Examined the potential for PEM fuel cells in diverse markets like stand-by power, fork lift trucks, and combined residential heat and power for the US. Work was a follow-on to a market penetration analysis for fuel cells in automotive markets.

An overview of Electric Vehicles and Plug-in Hybrid Electric Vehicles, European Commission Directorate-General Environment. Provided consultation to the EU concerning the impacts of an attributes-based standard such as weight-based standards on fuel economy and GHG emissions. Created a simple model that could verify the results of a very complex model with hundreds of inputs.

Analysis of Light Duty Vehicle Weight Reduction Potential, Department of Energy, Directed a large scope of study focusing on weight reduction technologies as capable of significant fuel economy improvement at potentially low costs. Utilized the staff capabilities developed in this area as a result of weight reduction analysis for the US EPA, California Air Resources Board (ARB) and other clients. Conducted high level meetings with weight reduction experts through his extensive contacts in the auto-industry and the Tier I supplier base.

PUBLICATIONS AND REPORTS

Mr. Duleep has over 50 publications in technical society and peer reviewed journals and has authored over 200 reports to clients. He also has authored two encyclopedia articles on Internal Combustion engine efficiency.

AWARDS/HONORS

SAE Award for Contribution to Public Policy Analysis, 2011

Directors List (First Rank), Wharton School, 1989

Merit Scholarship, University of Michigan, 1974

First Prize Winner, University Science Fair, India, 1971

PROFESSIONAL AFFILIATIONS

Tau Beta Pi (Engineering Honor Society)

Society of Automotive Engineers

LANGUAGES

English, Hindi and Tamil

EMPLOYMENT HISTORY

ICF International	Managing Director	2007-2011
Energy and Environmental Analysis, Inc.	Managing Director	1997-2007
Energy and Environmental Analysis, Inc.	Director	1988-1997
Energy and Environmental Analysis, Inc.	Senior Consultant	1979-1988
Bendix Electronics and Engine Control Systems Group	Senior Engineer	1976-1978
Aeronautical Development Establishment (India)	Junior Scientific Officer	1972-1973

APPENDIX "C"

Appendix C

Domestic Ethanol "Shuffling" in Response to the LCFS

Prepared by Edgeworth Economics

April 26, 2018

Since even before the LCFS was initially implemented, it has been noted that one potential mode of compliance could be fuel "shuffling," or rationalization of existing supplies, whereby fuels with different CI scores would be shifted between markets, with no beneficial impact on overall carbon emissions.[1] As described in a 2012 paper by researchers at U.C. Davis:[2]

> Shuffling will reduce the effectiveness of low-carbon fuel policies by appearing to achieve GHG emission reductions on paper even though no net GHG emission reduction takes place in reality. In the worst case, net emissions could actually increase due to the extra transport distance required to shuffle fuels and/or feedstock.

Most of the focus on the potential for fuel shuffling has been directed towards the markets for crude oil and the bilateral ethanol trade between the U.S. and Brazil.[3] However, given the numerous pathways with widely varying CI scores among domestic ethanol refineries, shuffling has been predicted as a likely compliance response for refined fuels within the U.S., as well.[4]

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[1] See, for example, Alexander Farrell, Daniel Sperling, et al., "A Low-Carbon Fuel Standard for California Part 1: Technical Analysis," Institute of Transportation Studies, U.C. Berkeley, May 29, 2007, p. 14.

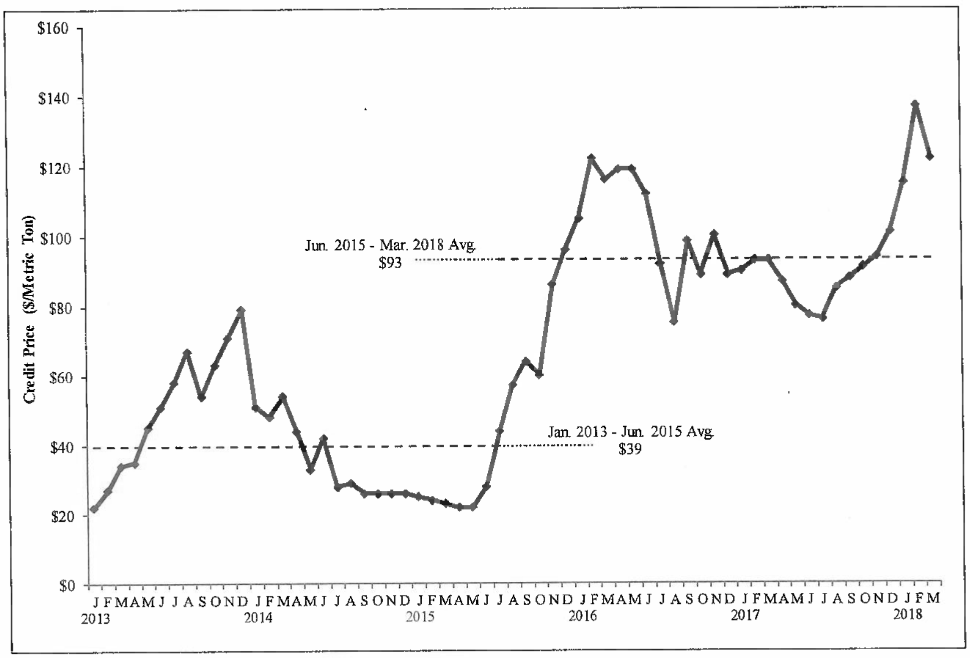
[2] Sonia Yeh, Daniel Sperling, et al., "National Low Carbon Fuel Standard: Policy Design Recommendations," Institute of Transportation Studies, U.C. Davis, July 2012, p. 72.

[3] See, for example, Sonia Yeh, Julie Witcover, and Jeff Kessler, "Status Review of California's Low Carbon Fuel Standard," Institute of Transportation Studies, U.C. Davis, Spring 2013, p. 6; and Sonia Yeh, Daniel Sperling, et al., "National Low Carbon Fuel Standard: Policy Design Recommendations," Institute of Transportation Studies, U.C. Davis, July 2012, p. 12.

[4] See, for example, "Response by Growth Energy to the Request for Comment on Proposals to Establish a Washington Clean Fuel Standard Program," comments submitted to the Washington Department of Ecology, March 4, 2015, pp. 8-9.

Prior to 2016, credit prices generally had remained low, averaging about $44 from 2013 through 2015. (See Figure 1.) The incentive for shuffling therefore had been muted. In late-2015, however, credit prices rapidly escalated, from $28 in June 2015 to as high as $122 in February 2016. A recent spike caused prices to reach a new monthly high of $137 in February 2018. Since July 2015, credit prices have averaged $93, compared to $39 prior to that date. Other factors equal, this shift would be expected to increase the incentives for fuel shuffling.

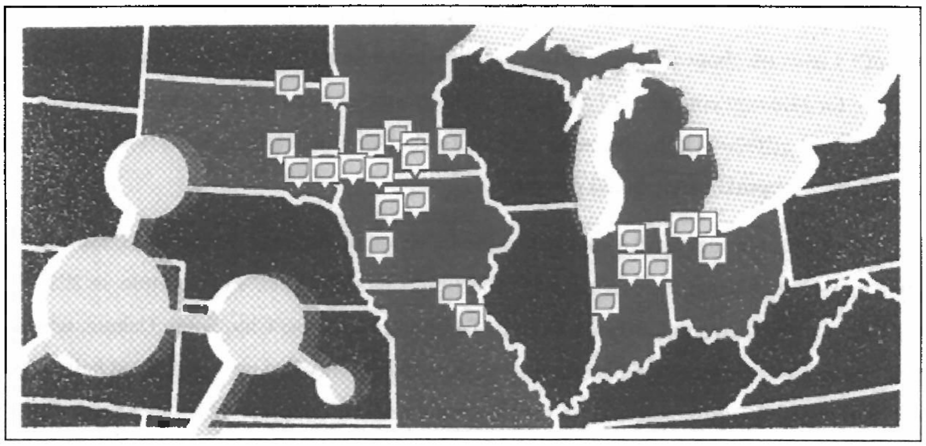
Figure 1
CARB Average Monthly Credit Price



Source: CARB website, www.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm.

Edgeworth Economics has been asked by Growth Energy to evaluate production and shipment data from POET, one of the largest U.S. ethanol refiners, to determine the extent to which refiners are shuffling domestic ethanol production and to identify potential consequences for emissions reductions and transportation costs. POET's operations provide a useful cross-section of U.S.-based refineries for this purpose, since the company manages 27 separate facilities across a broad region of the Midwest (see Figure 2) which have been assigned a wide range of CI scores.[5]

Figure 2
POET Ethanol Refineries



Source: POET website, poet.com/plants.

Prior to implementation of the LCFS in 2011, ethanol from all production facilities was essentially a fungible commodity. POET matched production facilities and customer locations based primarily on logistics costs and therefore organized deliveries to account for rail access, schedule, tariffs, and other factors. For example, POET never delivered ethanol to California from its plants located in the eastern part of its territory—Indiana, Ohio, and Michigan—but rather has used plants in South Dakota, Iowa, and Minnesota for this purpose, particularly those with favorable rail access. In 2010, POET delivered ethanol to California from 15 different facilities located in those three states.

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[5] Since 2005, POET has delivered ethanol to California from 17 different facilities, each producing and shipping at various times ethanol produced in combination with both "wet" and "dry" distillers grains with solubles ("WDGS" and "DDGS"). Production of DDGS requires additional energy, relative to WDGS, and therefore ethanol refined during a process that creates DDGS is assigned higher CI scores than ethanol refined during a WDGS process. Since implementation of the LCFS in 2011, POET has shipped ethanol to California from plants assigned CI scores in the range of 63.9 to 98.4 gCO2e/MJ.

3

Since the implementation of the LCFS in 2011, however, demand for ethanol by customers in California has been influenced by the CI score granted to the particular refineries and the contemporaneous price of credits, which together determines the financial impact of purchasing and blending ethanol from the various sources. The range of values of the credits generated by ethanol with different CI scores can be significant. At a credit price of $100, each point of CI is worth about $0.01 per gallon gasoline-equivalent ("gge"). Based on the pathways available for Midwest corn ethanol as of 2011, which were granted CI scores in the range of about 80 to 98 gCO2e/MJ, the difference in credit value for ethanol from POET's various plants was as high as approximately $0.20 per gge.

As a result of the penalty imposed by the LCFS on high-CI ethanol from the Midwest, POET immediately began rationalizing, or "shuffling," its shipments. For example, in 2011 POET ceased shipments to California from its facility in Big Stone City, South Dakota, which has a higher CI than other POET facilities. In 2010, that facility had provided about half of its total output—37.5 million gallons—to the California market, representing about 3 percent of California's requirement for fuel ethanol. Big Stone City, however, did not reduce its production of ethanol in 2011. Instead, the entire output of the facility was redirected to other markets in the U.S. Thus, higher CI fuel was simply sold to markets outside of California. Moreover, it is likely that overall emissions associated with the output of that facility increased, as the re-orientation of POET's logistics to other states likely involved greater transportation distances.

Another set of major adjustments for POET occurred in 2016, following the sharp increase in credit prices in late-2015. POET began to concentrate its California deliveries from a limited number of low-CI plants. In 2016, POET reduced the number of facilities delivering to California from 13 in 2015 to eight in 2016. By 2017, POET was delivering product to California from only three facilities, although the total quantity of ethanol delivered into California was essentially unchanged relative to 2010. Most of POET's California volumes now come from a single plant, Chancellor, which has received a favorable CI score due to its capability to use landfill gas and biomass as an energy source.

While the adjustment may help reduce the CI of California's fuel portfolio, the LCFS regulation does not maximize GHG benefits system-wide. The 12 POET facilities that delivered B4-101

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ethanol to California prior to the LCFS, but that no longer do so due to higher CI scores, are now simply shipping the same fuels outside California. Moreover, the increase in logistical costs associated with the reorganization of POET's deliveries likely has been associated with additional emissions from transport to less convenient locations.

B4-101 cont.

In summary, the incentives created by the LCFS credit mechanism have caused POET to reorganize its delivery pattern, with little, if any, change in the output from both its high-CI facilities and its low-CI facilities. The primary difference is that this reorganization has caused the company to incur greater logistics costs and likely has generated additional carbon emissions (relative to pre-LCFS) due to greater transportation distances.

Curriculum Vitae
For
Jesse David, Ph.D.

Edgeworth Economics

201 S. Lake Ave.
Suite 308
Pasadena, CA 91101
626-657-7950
jdavid@edgewortheconomics.com

Jesse David, Ph.D.

Jesse David heads the Los Angeles office for Edgeworth Economics. Dr. David is an expert on the valuation of intangible assets, market definition, and the assessment of economic impacts in complex commercial disputes and regulatory proceedings. His experience spans intellectual property, antitrust, labor, regulatory, and class certification matters, among other economic issues related to the intersection of business and government.

Dr. David has provided economic consulting and expert testimony for many industries, including pharmaceuticals, telecommunications, agricultural products, finance, petroleum products, chemicals, software, and consumer products. He frequently submits expert reports to and testifies before decision-making bodies, including U.S. federal and state courts, the Federal Energy Regulatory Commission, the National Energy Board of Canada, and various arbitration venues.

Dr. David's consulting practice also includes developing cost-benefit analyses of government regulations and assessing the economic impacts of government policies and other changes in industry structure. Dr. David has prepared studies for entities such as the American Trucking Association, the National Football League Players Association, the San Diego County Water Authority, the New York Power Authority, and the Ocean Conservancy.

EDUCATION

Stanford University
Ph.D., Economics, 2000

Brandeis University
B.A., *magna cum laude*, Economics and Physics, 1991

EMPLOYMENT

Edgeworth Economics, LLC, Washington, D.C.
2012 - present, Partner
2009 - 2012, Senior Vice President

Criterion Economics, LLC, Washington, D.C.
2009, Senior Vice President

National Economic Research Associates, Inc., White Plains, NY
2004 - 2009 Vice President
2000 - 2004 Senior Consultant
1997 - 1999 Senior Analyst

Stanford University, Palo Alto, CA
1993 - 1995 Research Assistant/Teaching Assistant

TESTIMONY AND EXPERT REPORTS

XY, LLC, Beckman Coulter, Inc. and Inguran, LLC d/b/a STgenetics v. Trans Ova Genetics, LC, U.S. District Court for the District of Colorado. Expert report, April 13, 2018.

Sandra Bond v. Berkshire Bank and Berkshire Hills Bancorp, U.S. District Court for the District of Massachusetts. Expert report, November 21, 2017; deposition, January 16, 2018.

DSM IP Assets, B.V. and DSM Bio-Based Products & Services, B.V. v. Lallemand Specialties, Inc. and Mascoma LLC, U.S. District Court for the Western District of Wisconsin. Expert report, November 21, 2017; deposition, December 14, 2017.

Abbott Laboratories, et al. v. Adelphia Supply USA, et al., U.S. District Court for the Eastern District of New York. Expert reports, November 15, 2017 and January 29, 2018; deposition, February 13, 2018.

Before an Interest Arbitration Board between the Northeast Illinois Regional Commuter Railroad Corporation and the Brotherhood of Railroad Signalmen, National Mediation Board. Expert report, October 20, 2017; arbitration testimony, November 8, 2017.

American Helios Constructors, LLC v. Shoals Technology Group, American Arbitration Association. Expert report, August 29, 2017.

Rembrandt Enterprises, Inc. v. Eurovo S.r.l., U.S. District Court for the Northern District of Iowa. Expert report, July 21, 2017.

United Energy Trading, LLC. v. Pacific Gas and Electric Company, et al., U.S. District Court for the Northern District of California, San Francisco Division. Expert report, May 19, 2017; deposition, September 28, 2017.

Staci Chester, et al. v. TJX Companies, Inc., et al., U.S. District Court for the Central District of California, Eastern Division. Declaration, April 17, 2017.

Stanley Johnson v. Time Warner Cable, et al., U.S. District Court for the District of South Carolina, Columbia Division. Declaration, March 24, 2017.

Momenta Pharmaceuticals, Inc. and Sandoz Inc. v. Amphastar Pharmaceuticals, Inc., et al., U.S. District Court for the District of Massachusetts. Expert report, February 16, 2017; deposition, March 28, 2017; trial testimony, July 18, 2017.

Chad Herron, et al. v. Best Buy Stores, LP, U.S. District Court for the Eastern District of California. Declaration, August 18, 2016; deposition, August 25, 2016.

In Re: AZEK Decking Sales Practices Litigation, U.S. District Court for the District of New Jersey. Declaration, July 25, 2016; deposition, August 17, 2016.

Boston Cab Dispatch, Inc. and EJT Management, Inc. v. Uber Technologies, Inc., U.S. District Court for the District of Massachusetts. Expert report, May 20, 2016.

In Re: Nest Labs Litigation, U.S. District Court for the Northern District of California. Declaration, April 15, 2016; deposition, May 10, 2016.

The Bakery, LLC, et al. v. Kenneth Pritt and Woodford Transportation, LLC, et al., Circuit Court of Greenbrier County, West Virginia. Expert reports, March 21, 2016 and May 27, 2016.

In Re: Scotts EZ Seed Litigation, U.S. District Court for the Southern District of New York. Expert report, March 11, 2016; deposition, April 20, 2016.

Digital Recognition Network, Inc. v. Accurate Adjustments, Inc., et al., U.S. District Court for the Northern District of Texas, Fort Worth Division. Expert reports, January 22, 2016 and February 22, 2016; deposition, February 25, 2016.

American Helios Contractors, LLC v. Bradley Kogan, Precision Renewables, LLC, and 3TAC, LLC, District Court for Clark County Nevada. Expert report, November 13, 2015.

Christopher Lewert v. Boiron, Inc. and Boiron USA, Inc., U.S. District Court for the Central District of California. Expert report, October 1, 2015; deposition, April 14, 2016.

Wreal, LLC v. Amazon.com, Inc., U.S. District Court for the Southern District of Florida, Miami Division. Expert report, September 10, 2015; deposition, September 28, 2015.

Novadaq Technologies Inc. v. Karl Storz Endoscopy-America, Inc. and Karl Storz GmbH & Co. KG, U.S. District Court for the Northern District of California, San Jose Division. Expert report, July 28, 2015; declaration, November 10, 2015.

Globus Medical, Inc. v. DePuy Synthes Products, LLC and DePuy Synthes Sales, Inc., U.S. District Court for the District of Delaware. Expert reports, July 22, 2015 and October 14, 2015; deposition, November 6, 2015.

Broadband iTV, Inc. v. Hawaiian Telcom, Inc., et al., U.S. District Court for the District of Hawaii. Expert reports, June 30, 2015 and July 28, 2015; declaration, July 10, 2015; deposition, July 29, 2015.

Greater Houston Transportation Company, et al. v. Uber Technologies, Inc. and Lyft Inc., U.S. District Court for the Southern District of Texas, Houston Division. Expert reports, June 29, 2015 and November 19, 2015; declaration, August 27, 2015; deposition, January 8, 2016.

Crystal Good, et al. v. American Water Works Company, Inc., et al., U.S. District Court for the Southern District of West Virginia. Expert report, May 22, 2015; deposition, June 12, 2015.

In Re: Processed Egg Products Antitrust Litigation, U.S. District Court for the Eastern District of Pennsylvania. Expert report, March 13, 2015; deposition, May 5, 2015; affidavit, September 8, 2015; hearing testimony, December 16, 2015.

Santarus, Inc. and The Curators of the University of Missouri v. Par Pharmaceutical, Inc., U.S. District Court for the District of Delaware. Expert report, April 21, 2014; deposition, June 12, 2014.

Mylan Technologies, Inc. formerly known as Bertek, Inc., and Mylan, Inc. v. Zydus Noveltech, Inc., Sharad K. Govil, Cadila Healthcare Ltd., also known as Zydus Cadila, Pankaj Patel, and Sunil Roy, Vermont Superior Court, Chittenden Civil Division. Expert report, October 2, 2013; deposition, November 19, 2013.

Alcon Pharmaceuticals Ltd. and Alcon Research, Ltd. v. Lupin Ltd. and Lupin Pharmaceuticals, Inc., U.S. District Court for the District of Delaware. Expert report, June 28, 2013; deposition, July 24, 2013.

Warner Chilcott Company, LLC v. Lupin Ltd. and Lupin Pharmaceuticals, Inc., and *Warner Chilcott Company, LLC v. Watson Laboratories, Inc.*, U.S. District Court for the District of New Jersey. Expert report, June 12, 2013; deposition, July 11, 2013; trial testimony, October 8, 2013.

In Re: Mushroom Direct Purchaser Antitrust Litigation, U.S. District Court for the Eastern District of Pennsylvania. Expert report, May 15, 2013; deposition, October 25, 2013; hearing testimony, March 24-25, 2015.

Lisy Corp. v. Barry A. Adams, McCormick & Company, Inc. and Mojave Foods Corporation, Circuit Court for Howard County, Maryland. Deposition, May 23, 2012; trial testimony, April 26, 2013.

Dey, L.P. and Dey, Inc. v. Teva Parenteral Medicines, Inc., et al., U.S. District Court for the Northern District of West Virginia. Expert report, January 13, 2012; deposition, February 7, 2012; trial testimony, August 2, 2013.

Dow Corning Corporation and Hemlock Semiconductor Corporation v. Jie (George) Xiao, LXEng LLC, and LXE Solar, Inc., U.S. District Court for the Eastern District of Michigan, Northern Division. Declaration, January 9, 2012; expert report, March 1, 2012.

Riverplace Development, LLC v. Charles Cranford, Esquire and Rogers Towers, P.A., Circuit Court, Fourth Judicial Circuit, in and for Duval County, Florida. Depositions, October 12, 2011 and December 21, 2011.

Pfizer, Inc., et al. v. Teva Pharmaceuticals USA, Inc. and Teva Pharmaceuticals Industries, Ltd., U.S. District Court for the District of Delaware. Expert report, June 3, 2011; deposition, July 22, 2011.

Ramona Trombley, et al. v. National City Bank, U.S. District Court for the District of California. Expert report, May 27, 2011; declaration, August 29, 2011.

Rocky Mountain Farmers Union, et al. v. James N. Goldstene, U.S. District Court for the Eastern District of California. Declarations, October 29, 2010 and March 14, 2011.

Investment Technology Group, Inc., et al. v. Liquidnet Holdings, Inc., U.S. District Court for the Southern District of New York. Expert report, April 12, 2010; deposition, June 2, 2010.

AOB Properties, Ltd. v. Laserspine Institute, LLC, et al., U.S. District Court for the Middle District of Florida, Tampa Division. Expert report, December 11, 2009.

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Tyco Healthcare Group LP and Mallinckrodt Inc. v. Pharmaceutical Holdings Corporation, Mutual Pharmaceutical Company, Inc. and United Research Laboratories, Inc., U.S. District Court for the District of New Jersey. Declaration, July 22, 2009; deposition, July 23, 2009; hearing testimony, July 29, 2009.

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APPENDIX "D"

Comments on the CaGREET3.0 Model and Corn and Sugarcane Calculators

April 23, 2018

By Thomas Darlington, Air Improvement Resource Inc.
Donald O'Connor, (S&T)[2] Consultants Inc.

In connection with its consideration of the amendments to the LCFS regulation, ARB has developed a new model, CaGREET3.0, to determine the carbon intensity ("CI") of various regulated fuels. To develop the new model, CARB adapted most of the Argonne GREET2016 model. We support this method in general; that is, that the California GREET model should be consistent with the latest Argonne GREET model and data for corn farming and other factors. We are concerned, however, that CARB did not incorporate some important components of the Argonne GREET2016 model, and that certain aspects of the CaGREET3.0 model are not supported by the evidence. B4-102

<u>Corn Ethanol</u>

ARB made the corn ethanol emissions in CaGREET3.0 to be mostly consistent with the GREET2016 model. We have two comments on this update: (1) staff did not include the distillers' grains methane credit in GREET2016, and (2) the emissions for medium and heavy-duty trucks appear to be out-of-date. B4-103 B4-104

Distillers Grains Methane Avoidance Credit

In addition to ethanol, all dry mill ethanol plants produce distillers' grains, which are fed to livestock. The distillers' grains can either be wet (used immediately), or it can be dried and used later. Beef cattle that are fed distillers grains (either wet or dry) have reduced enteric fermentation as compared to cattle that are not fed this product, and the result is lower methane emissions overall from cattle. Methane is a greenhouse gas. The emission credit from reduced methane emissions from cattle is called the DDG methane avoidance credit.

GREET2016 contains distillers' grains (DDG) methane avoidance credit. The credit is 2.1 g/MJ, which is sufficient to have a material effect on the CI of an applicant's pathway. ARB's rationale for not including this credit is stated in its report on CaGREET2.0. B4-105

> There is no credit for reduced enteric fermentation emissions due to the inclusion of DGS in livestock ratios in LCFS ethanol pathways. The animals consuming the DGS are not currently in the LCFS LCA ethanol system boundary. [1]

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[1] *CA-GREET 2.0 Supplemental Document and Tables of Changes*, ARB Staff Update, June 4, 2015, page 49.

This stated reason for not including the DGS methane avoidance credit is inconsistent with ARB's granting of a LCFS pathway for methane produced from livestock manure, in which case the pathway was allowed a substantial credit for methane avoidance similar to the methane avoidance credit for DGS.[2] If ARB allows a methane avoidance credit for methane produced from manure, ARB should allow a methane avoidance credit for corn ethanol from DGS use as well.

CARB staff's decision to not provide a DDG methane avoidance credit is also inconsistent with ISO life cycle assessment (LCA) standards. The LCA concept emerged in the late 1980's from competition among manufacturers attempting to persuade users about the superiority of one product choice over another. As more comparative studies were released with conflicting claims, it became evident that different approaches were being taken related to the key elements in the LCA analysis:

- Boundary conditions (the "reach" or "extent" of the product system);
- Data sources (actual vs. modeled); and
- Definition of the functional unit.

In order to address these issues and to standardize LCA methodologies and streamline the international marketplace, the International Standards Organization (ISO) developed a series of international LCA standards, specifications, and technical reports under its ISO 14000 Environmental Management series. The main contribution of these ISO standards was the establishment of the LCA framework that addressed the inconsistencies and allowed for proper comparisons between products or systems. B4-105 cont.

CARB staff's decision to not provide a DDG methane avoidance credit is also inconsistent with ISO LCA standards. In CARB's approach, the lifecycle system boundary includes the production and use of corn ethanol but only the production of the DDG. This approach is inconsistent with the ISO LCA standard 14044, which states:

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[2] Pathway T2R-1062, Fuel Producer: California Bioenergy LLC (B194) Facility Name: Kern County Dairy Biogas Cluster (B2139). Dairy Biogas from Kern County from dairy manure covered aneaerobic lagoons to CNG in California (accounting for avoided methane per ARB Livestock Offset Protocol), https://www.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm. Pathway CI is -272.97 for the LCFS.

> LCA addresses the environmental aspects and potential environmental impacts (e.g. use of resources and environmental consequences of releases) throughout a product's life cycle from raw material acquisition through production, use, end-of-life treatment, recycling, and final disposal (i.e. cradle-to-grave).[3]

B4-105 continued from previous page, continues to footnote below

CARB have deviated from international norms by effectively truncating the system boundary so as to exclude the emission benefits of the use of DDG compared to other animal feeds.

Trucking Transport Emissions

Table 1 shows the fuel economy and energy consumption of medium-heavy and heavy-heavy duty diesel trucks in CaGREET3.0.

Table 1. Energy Consumption of MHDT and HHDT Trucks in CaGREET3.0

Truck Type	Fuel economy (mpg)	Energy Consumption (Btu/mile)	BTU/ton
HHDT	5.3	24,236	1,616
MHDT	10.4	12,351	1,544

As shown in Table 1, the energy use for HHDTs is higher than for MHDTs. In CaGREET3.0, it is not logical that the energy use per ton-mile is lower for a medium duty truck than it is for a heavy-duty truck. CaGREET3.0 overestimates the fuel use for a heavy-duty truck and underestimated the fuel use for a medium duty truck compared to the most recent values in the Oakridge National Laboratories Transportation Energy Use Data Book (see Table 2).[4]

B4-106 continues to footnote below and next page

Table 2. Trucking Fuel Economies in CaGREET3.0

Vehicle Type	CA GREET (mpg)	Transportation Energy Use Data Book (mpg)
MDT	10.4	7.4
HDT	5.3	5.9

In addition to the energy use being questionable, the load size is too small for the heavy-duty truck at only 15 tons. While the maximum load size will vary by state a typical value is 20 tons for a heavy-duty truck.

Table 3 shows the impact of making changes in the fuel economies for MHDTs and HHDTs, and also a change in load size for HHDTs from 15 to 20 tons.

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[3] https://www.iso.org/obp/ui/#iso:std:iso:14044:ed-1:v1:en

B4-105 continued from above

[4] Transportation Energy Data Book. https://cta.ornl.gov/data/index.shtml

B4-106 continued from above

Table 3. Impacts of Fuel Economy Change and Load Size Change on Corn Feedstock Production	
Case	Feedstock Production CI (g/MJ)
CaGREET3.0 Default	17.33
Updated fuel economies (see Table 2)	17.31
Updated fuel economy and load change	17.04

B4-106 cont.

Furthermore using the same energy per ton-mile for the delivery as the return trip (backhaul) is not appropriate as the load is on the order of 50%. The impact of all of the transportation issues is that the transport emissions are overstated.

Sugarcane Ethanol

We have several comments on the sugarcane ethanol emissions: (1) the quantity of nitrogen in sugarcane in aboveground residues has been set to the lowest value found in literature; also the nitrogen in the root biomass is not included in GHG calculations, (2) the amount of fertilizer applied to sugarcane is 40% lower than the Brazilians use their emissions model, and (3) N_2O emissions from nitrogen in fertilizer are too low and not consistent with N_2O emissions from fertilizer in other countries. These issues are discussed further below. B4-107a B4-107b B4-107c

Estimated nitrogen amounts in sugarcane, and fertilizer amounts

Estimated nitrogen amounts in the biomass and fertilizer of sugarcane in CaGREET3.0 are shown in Table 4.

Table 4. Nitrogen Input Comparison		
Component	Ca GREET2.0	Ca GREET3.0
Fertilizer	800	1,025**
Crop Residue*	1,036	705
Filtercake	36	36
Vinasse	205	205
Roots	0	0
Total	2,077	2,302

*Referred to as "above and below biomass" in GREET. But it does not include the biomass of the roots.
** Includes 225 g "supplemental N"

B4-107d

The CaGREET3.0 value for the nitrogen content of the aboveground biomass emanates from GREET 2012 rev 2. The data sources and the values are shown in the following table.

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Table 5. GREET Sugarcane Biomass N Content	
Source	Value
Macedo [5]	0.37%
Seabra et al. [6]	0.60%
Lisboa[7]	0.50%
Gava et al. [8]	0.64%
Adopted in GREET 2012	0.37%

GREET adopted the lowest value in the literature for sugarcane. There is no explanation for the selection of this value in the ISOR or related materials. Nor is there any evidence to suggest this value is realistic. In fact, the studies adopted after 2012 show the value should be much higher. The Leite paper, for example, recently measured the nitrogen content.[9] They reported a value of 0.54% for nitrogen. Looking at the reported N content of biomass per tonne of sugar cane, they found a value of 864 g N/tonne of cane. This does not include the nitrogen in the roots.

B4-107d
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The nitrogen inputs values in CaGREET3.0 are also understated because they do not include nitrogen in the roots. The importance of including nitrogen in the roots was demonstrated in a discussion of the Canasoft model that is part of the Virtual Sugarcane Biorefinery (VSB) modeling system (Bonomi et al, 2016). That study found that the sugarcane root system is renewed each year by re-growth of ratoon. Emissions of root system are estimated using the root's nitrogen content and the amount of root system, calculated with a root-stalks ratio of 0.2. The root nitrogen content considered is 0.514 %. This reveals there is an additional 304 g N/tonne of cane from the roots. The total biomass N is therefore 1,168 g N/tonne of cane, 23.5% higher than the value in CaGREET3.0.

The VSB also reports the other inputs that are summarized and compared to the CaGREET3.0 values in the following table. B4-107e

[5] *Sugar Cane's Energy: Twelve studies on Brazilian sugar cane agribusiness and its sustainability,* Macedo, I.C., 20072nd ed. UNICA.

[6] *Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use*, Seabra, J., Macedo, I., Chum, H., Faroni, C., Sarto, C. A Biofuels, Bioproducts and Biorefining, 2011, V5, 519–532

[7] *Bioethanol production from sugarcane and emissions of greenhouse gases – known and unknowns.* Lisboa, C.C., Butterbach-Bahl, K., Mauder, M., Kiese, R., 2011GCB Bioenergy 3, 277–292.

[8] *Urea and sugarcane straw nitrogen balance in a soil-sugarcane crop system*, Gava, G.J. de C., Trivelin, P.C.O., Vitti, A.C., Oliveira, M.W. de, 2005. Pesquisa Agropecuária Brasileira 40, 689–695.

[9] *Nutrient Partitioning and Stoichiometry in Unburnt Sugarcane Ratoon at Varying Yield Levels,* Leite, J.M., Ciampitti, I.A., Mariano, E., Vieira-Megda, M.X., Trivelin, P.C.O., Frontiers in Plant Science, 20 April 2016.

B4-107d
continued from above

Table 6. VSB Inputs vs. CaGREET3.0 (Sugarcane)		
	CaGREET3.0	VSB
Nitrogen, g/tonne cane	800	1,342
Phosphorus, g/tonne cane	300	203
Potassium, g/tonne cane	1,000	1,420

Not only is the biomass N underestimated in GREET but the synthetic fertilizer is also underestimated. The following table compares the nitrogen inputs from GREET 2013, CA GREET 2.0, and the best available data.

B4-107e cont.

Table 7. Nitrogen Input Comparison for Sugarcane (Kg N/tonne cane)			
	CaGREET 2.0	CaGREET3.0	Best Available Data
Fertilizer	800	1,025	1,342
Crop Residue	1,036	705	864
Filtercake	36	36	36
Vinasse	205	205	205
Roots	0	0	305
Total	2,077	2,302	2,752

The carbon intensity of sugarcane ethanol is shown with CaGREET3.0 and the best available data in Table 8. Emissions using best available nitrogen data are 4.78 g/MJ higher than CaGREET3.0. Clearly, at least the 305 g root nitrogen should be added to CaGREET3.0 since it is currently not counted.

Table 8. CI of Sugarcane Ethanol		
Scenario	g CO2e/MJ	
	Feedstock Production CI	Total CI
CaGREET3.0	21.17	51.11
Best Available Data	26.13	55.89

N as N_2O Emissions from Sugarcane.

The N_2O emission factors in CaGREET3.0 are shown in Table 8. The N_2O fractions are shown for the nitrogen from biomass and nitrogen from fertilizer. All of the biomass nitrogen is at 1.225%, which is the IPCC default level for biomass. The nitrogen from fertilizer is given an extra 0.1% to account for volatilization of nitrogen from fertilizer, which does not occur for the biomass. But the value being used for fertilizer in Brazil is 1.220%. This value comes from the GREET model. This value for fertilizer in Brazil should be changed to 1.325% to be consistent with the IPCC default value, and to be consistent with N_2O from fertilizer in the US. B4-107f

Table 9. N_2O Emissions: N in N_2O as % of N in N Fertilizer and Biomass

Biomass						Fertilizer	
Corn Farming	Switchgrass	Miscanthus	Corn Stover	Sorghum	Sugarcane	Nitrogen fertilizer in the US	Nitrogen fertilizer in Brazil
1.225%	1.225%	1.225%	1.225%	1.225%	1.225%	1.325%	1.220%

When the N in N_2O in fertilizer is increased to 1.325% from 1.220%, the CI increases by 0.43 gCO2e/MJ (56.32 instead of the 55.89 in Table 8)

Curriculum Vitae
For
Thomas Darlington
And
Donald O'Connor

Thomas L. Darlington
President, Air Improvement Resource Inc.

Profile

Thomas L. Darlington is President of Air Improvement Resource, a company formed in 1994 specializing in mobile source emission modeling. He is an internationally recognized expert in mobile source emissions modeling, lifecycle analysis, and land use modeling.

Professional Experience

1994-Present	President, Air Improvement Resource
1993-1994	Director, Mobile Source Programs, Systems Application International
1989-1994	Senior Engineer, General Motors Corporation, Environmental Activities
1988-1989	Senior Project Engineer, Detroit Diesel Corporation
1979-1988	Project Manager, U.S. EPA, Ann Arbor, Michigan

Recent Major Projects

- Provided numerous OMEGA outputs to The Alliance for their review of the 2022-2025 GHG standards
- Participating on behalf of Growth Energy in EPA's MOVES model development stakeholder meetings
- Creating a new California emissions model for offroad equipment
- Published a Society of Automotive Engineers paper at SAE World Congress in 2017 (April 2017) on modeling GHG emission reductions with a high octane, low carbon biofuel (Minnesota Corn Growers and others)
- Published an SAE paper at the 2016 World Congress on our review of EPA's EPAct fuels testing and modeling (Growth Energy)
- Developed Life Cycle reports and complete applications for 8 plants for the California Low Carbon Fuel Standard
- Participated in and provided written comments on California's three 2014 Indirect Land Use (iLUC) workshops (Growth Energy)
- With Purdue University, conducted study of iLUC emissions of rapeseed and other oilseeds in 2013 utilizing an updated version of GTAP (European Biodiesel Board)
- Reviewed EPA's palm oil iLUC emissions in 2013 (NESTE)
- Submitted comments on ARB's new GREET2.0 model
- Reviewed CARB's land use emissions for soybean biodiesel
- Reviewed the land use impacts of the RFS2 from EPA, including the notice of Proposed Rule, Regulatory Impact Analysis, and approximately one hundred documents in the rulemaking docket.

Air Improvement Resource, Inc. 10820 Boyce Rd, Chelsea, Michigan 48118
Phone: 248-921-5096

- Completed a land use study for Renewable Fuels Association and reviewed California Air Resource Board's Initial Statement of Reasons for the Low Carbon Fuel Standard
- Represented three stakeholders in the recent development of the ARB Predictive Model for reformulated gasoline in California (Alliance of Automobile Manufacturers, Renewable Fuels Association and Western States Petroleum Association)
- Represented two stakeholders in EPA's development of the MOVES on-highway emissions model (Alliance of Automobile Manufacturers and Engine Manufacturers Association)
- Developed the effects of ethanol permeation on on-highway and off-highway mobile sources in California and other states for the American Petroleum Institute
- Studied gasoline and diesel fuel options for Southeast Michigan (for SEMCOG, API and Alliance of Automobile Manufacturers)

Recent Publications

Darlington, T., Herwick, G., Kahlbaum, D., and Drake, D., "Modeling the Impact of Reducing Vehicle Greenhouse Gas Emissions with High Compression Engines and High Octane Low Carbon Fuels," SAE 2017-01-0906, 2017, doi: 10.4271/2017-01-0906.

Darlington, T., Kahlbaum, D., Van Hulzen, S., and Furey, R., "Analysis of EPAct Emission Data Using T70 as an Additional Predictor of PM Emissions from Tier 2 Gasoline Vehicles", SAE Technical Paper 2016-01-0996, 2016, doi: 10.4271/2016-01-0996.

"Study of Transportation Fuel Life Cycle Analysis: Review of Economic Models Used to Assess Land Use Effects", CRC-E-88-3, July 2014.

"Land Use Change Greenhouse Gas Emissions of European Biofuel Policies Utilizing the Global Trade Analysis Project Model", Darlington, Kahlbaum, O'Connor, and Mueller, August 30, 2013.

"A Comparison of Corn Ethanol Lifecycle Analyses: California Low Carbon Fuels Standard (LCFS) Versus Renewable Fuels Standard (RFS2)", June 14, 2010. Renewable Fuels Association and Nebraska Corn Board. This study compared and contrasted the corn ethanol lifecycle analyses performed by both CARB (as a part of the LCFS) and the EPA (as a part of RFS2).

"Review of EPA's RFS2 Lifecycle Emissions Analysis for Corn Ethanol", September 25, 2009. Conducted for Renewable Fuels Association. This study reviewed EPA's land use GHG emissions assessment for corn ethanol, including the FASOM and FAPRI models and Winrock land-use types converted and emission factors by ecosystem type. The study made many recommendations for improving the land-use and emissions modeling.

"Review of CARB's Low Carbon Fuel Standard Proposal", April 15, 2009. Conducted for Renewable Fuels Association. This study reviewed CARB's analysis of land use emissions using GTAP6 and CARB's overall lifecycle emissions for corn ethanol. This study made many recommendations for improving the land use and lifecycle emissions of corn ethanol.

"Emission Benefits of a National Clean Gasoline", August 2008. Conducted for the Alliance of Automobile Manufacturers. This study evaluated the nationwide criteria pollutant emission reductions of a national clean gasoline standard.

"Land Use Effects of Corn-Based Ethanol", February 25, 2009. Conducted for Renewable Fuels Association. This study evaluates possible land use changes and GHG emissions associated with these land use changes as a result of the renewable fuel standard mandated 15 billion gallons of corn ethanol required by calendar year 2015. The study utilized projections of land use in the US and rest of world performed by Informa Economics, LLC, as well as newer estimates of the land use credits of co-products produced by ethanol plants to evaluate possible land use changes.

"On-Road NOx Emission Rates From 1994-2003 Heavy-Duty Trucks", SAE2008-01-1299, conducted for the Engine Manufacturers Association. This study examined manufacturers consent decree emissions data to determine on-road NOx emission rates, and deterioration in emissions from heavy-duty vehicles. (Peer reviewed publication)

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act - Part 2: CO2 and GHG Impacts", SAE2008-01-1853, conducted for the Alliance of Automobile Manufacturers. This paper evaluated the comparison of greenhouse gases from cars and light trucks in the US under both the Federal and California GHG policies. (Peer reviewed publication)

"Effectiveness of the California Light Duty Vehicle Regulations as Compared to Federal Regulations", June 15, 2007. Conducted with NERA Economic Consulting and Sierra Research for The Alliance of Automobile Manufacturers. This study compares the emission benefits of the California and Federal light duty vehicle regulations for HC, CO, NOx, PM, SOx, and Toxics taking into account the difference in emission standards, new vehicle costs and its effect on fleet turnover, new vehicle fuel economy and its effect on vehicle miles traveled, and other factors. Both the EPA MOBILE6 and ARB EMFAC on-road emissions models were used to estimate changes in emissions inventories.

"The Case for a Dual Tech 4 Model Within the California Predictive Model", May 20, 2007. Conducted with ICF International and Transportation Fuels Consulting for the Renewable Fuels Association (RFA). This study developed separate emissions vs fuel property models for lower and higher Tech 4 (1986-1995) vehicles, and showed that utilizing this alternative Predictive Model would result in a higher compliance margin for fuels containing higher volumes of ethanol. It was thought that this could lead to higher ethanol concentrations in the state, but even if the dual model is not used, it is a better representation of the 2015 inventory than the ARB single model.

"Updated Final Report, Effects of Gasoline Ethanol Blends on Permeation Emissions Contribution to VOC Inventory From On-Road and Off-Road Sources, Inclusion of E-65 Phase 3 Data and Other Updates", June 20, 2007. Conducted for the American Petroleum Institute. This report updates the earlier March 3, 2005 report for API utilizing data collected by CRC and others since of the time of the earlier report.

Final Report, Development of Technical Information for a Regional Fuels Strategy, February 28, 2006. Conducted for the Lake Air Directors Consortium (LADCO). This report provided guidance to the LADCO states (Midwestern states) concerning how to model different types of fuel control programs (in particular) using EPA mobile source models, and how to set up the baseline input files so that results are consistent between the different states.

"Emission Reductions from Changes to Gasoline and Diesel Specifications and Diesel Engine Retrofits in the Southeast Michigan Area", February 23, 2005. Conducted for the Southeast Michigan Council of Governments (SEMCOG), the Alliance of Automobile Manufacturers, and the American Petroleum Institute. This study examined the on-road and off-road emission benefits of many different possible gasoline and diesel fuel specifications that the state could adopt to help meet the 8-hour ozone standards. This study formed the basis for the state's move to lower RVP summer gasoline.

"Examination of Temperature and RVP Effects on CO Emissions in EPA's Certification Database, Final Report", CRC Project No. E-74a, April 11, 2005. Conducted for the Coordinating Research Council. This study compared CO vs temperature results from the MOBILE6 model to the certification data, and recommended further testing, which is being conducted by the CRC at this time.

"Effects of Gasoline Ethanol Blends on Permeation Emissions Contribution to VOC Inventory From On-Road and Off-Road Sources" March 3, 2005. Conducted for the American Petroleum Institute (API). Using data from the CRC-E-65 program, and data collected by the California EPA and Federal EPA, this study estimated the impacts of ethanol use on increasing permeation VOC emissions from on-road vehicles, off-road equipment and vehicles, and from portable containers. Emission inventory estimates were made for a number of geographical areas including the state of California, and results showed that the permeation effect increases anthropogenic VOC inventories by 2-4%.

Review of EPA Report "A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions", February 11, 2003. Conducted for the American Petroleum Institute. This study critically examined the methods that EPA used to develop the impacts of biodiesel fuels on HC, CO, NOx, and PM emissions.

"Well-To Wheels Analysis of Advanced Fuel/Vehicle Systems – A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions", May 2005. Conducted for General Motors Corporation, with Argonne National Labs. This study examined many different well to wheels pathways for various fuels, and their impacts on GHG and criteria pollutant emissions.

"Potential Delaware Air Emission Impacts of Switching From MTBE to Ethanol in the Reformulated Gasoline Program", May 26, 2005. Conducted for Lyondell Chemical Company. This study examined the HC, CO, and NOx impacts of switching from MTBE to ethanol.

"Potential Massachusetts Air Emission Impacts of Switching From MTBE to Ethanol in the Reformulated Gasoline Program" June 17, 2005. Conducted for Lyondell Chemical Company. This study is similar to the Delaware study above.

"Potential Maryland Air Emission Impacts of a Ban on MTBE in the Reformulated Gasoline Program", October 18, 2005. Conducted for Lyondell Chemical Company. This study is similar to the Delaware study above.

"MOBILE6.2C with Ethanol Permeation and Ethanol NOx Effects", February 8, 2005. Conducted for Health Canada. This study modified the MOBILE6.2C model for ethanol permeation VOC and ethanol NOx effects.

Education

B. Sc., (Materials and Metallurgical Engineering), University of Michigan, Ann Arbor, 1979
Post Graduate Courses (Business Administration), University of Michigan, Ann Arbor, 1982

Air Improvement Resource, Inc. 10820 Boyce Rd, Chelsea, Michigan 48118
Phone: 248-921-5096

Donald Victor O'Connor, P. Eng.

Summary

An innovative, achievement oriented business leader with over 40 years experience with energy and environmental issues in Canada. Successfully developed and commercialized environmentally sound energy alternatives.
Background includes:

- Development of the GHGenius life cycle assessment model for energy systems.
- Developing Canada's largest alternative fuel retailing program.
- Establishment of the ethanol industry in Western Canada, from manufacturing to retailing. Extensive experience with production of biofuels.
- Detailed knowledge of fuels and the fuels industry. Technical expertise regarding the utilization of methanol, ethanol, natural gas, propane, hydrogen, gasoline and diesel fuels.
- Developing objectives, strategy and tactics in highly competitive manufacturing and retail industries.

Professional Experience

(S&T)² Consultants Inc. (1998-2018)
President
The firm specializes in energy and environment issues. (S&T)² helps corporations with business development strategies concerning new energy markets and products and it helps governments understand the business, energy and environmental issues of new energy pathways.
Mr. O'Connor has recently provided strategic advice on fuels, transportation issues, and greenhouse gas emissions to a number of Provincial governments, several Canadian Federal Government departments, and international agencies and governments. Mr. O'Connor has also consulted for a number of companies developing new technologies for alternative fuelled vehicles and companies developing new transportation fuel processes and facilities.

Projects have included:

- Development of the GHGenius life cycle assessment model
- Development of the Ontario Ethanol Growth Fund. Led to the establishment of 50% of the Canadian ethanol production capacity.
- Analysis of the US EPA RFS program for the National Biodiesel Board. Resulted in soybean biodiesel passing the GHG emission threshold established by the US Congress.
- Establishment of the qualifying criteria for biofuels under the Alberta RFS program.
- Proposed and participated in the development of a novel, patented process for the production of ethanol from woody lignocellulosic feedstock. Five patents granted.
- Provided guidance and recommendations for the establishment of a biofuels program for the Government of Peru.
- Provided project development services for the development and construction of western Canada's largest fuel ethanol plant.

Mohawk Canada Limited (1981 – 1998)
Mohawk was Western Canada's largest independent automotive fuel retailer offering environmentally responsible fuels and lubricants through 300 retail and bulk facilities. Mohawk also manufactures re-refined lubricants from used oil, and ethanol, distillers' grains and Fibrotein from grain.

President, COO, and Director, Mohawk Products Ltd. (1997 – 1998)
President, COO, and Director, Mohawk Lubricants Ltd. (1992 – 1998)
Vice President, Supply and Manufacturing (1989 – 1998)
Various positions in R&D, manufacturing and supply (1981-1989)

Donald Victor O'Connor, P. Eng.

Responsibilities:

- Led and managed three business units simultaneously. These units manufactured lubricants from used oil, processed grain into ethanol and human and animal foods, and the corporate supply function covering all aspects of fuels' development, supply and distribution, and core supplier relationships for convenience goods and corporate services. Recommended objectives, strategy and tactics consistent with the organization's values to achieve corporate vision.

Accomplishments:

- Contributed to the development of a vision and unique corporate positioning that allowed the company to increase its market share by 50% over five years;
- Initiated and led the successful introduction of several new or differentiated alternative fuels to the market (Natural Gas, M85, Ethanol blends (Regular Plus and Premium Plus), and premium diesel fuels (Diesel with ECA and Diesel Max);
- Led the turnaround of used oil re-refining business by doubling production and sales over a four-year period. Increased bottom line by 500% and made the operation the most profitable of its kind in the world.
- Introduced a strategic sourcing program throughout the organization.

Additional Professional Activities

- Advisory Committee. ILUC Quantification Study of EU Biofuels. GLOBIOM Model ILUC project.
- Canadian expert on GHG emissions and indirect effects to ISO TC 248 developing ISO 13065.
- Expert Working Group on Indirect Effects. California Air Resources Board. 2010
- Canadian Biomass Innovation Network. External Advisory Panel. 2005-2010.
- Director, B.C. Buildings Corporation. 2000-2002
- Co-Chair 1999-2001. Member, Executive Committee on Cleaner Technology Vehicles (Minister's Committee, B.C. Environment) (1995 - 2001)
- Director, Pound-Maker Adventures (1990 - 1998) An integrated ethanol plant cattle feeding operation in Saskatchewan.
- Director, Canadian Renewable Fuels Association (1990 – 1998, 2000-2002)
- Member, Environment Advisory Committee, Vancouver Foundation (2001-2003)
- Member, Ethanol BC Board (2000-2010)
- Member, Bio-based Products R&D Advisory Council, BIOCAP Canada, (2002-2003)
- Member, National Advisory Committee on Bioenergy (1984 - 1990)
- Member, Efficiency and Alternative Energy Committee, Minister's National Advisory Council to CANMET (1990 - 1994)
- Chair, Ethanol Program Advisory Committee, Agriculture and Agrifood Canada (1992 - 1997)
- Canadian Petroleum Products Institute, Western Division Management Committee (1996 - 1998)
- Numerous presentations on alternative fuels at National and International conferences.

Employment

- Manager, Energy and Environmental Technology, B.H. Levelton & Associates Ltd. Consulting Engineers (1974 - 1981)
- Air Engineer, Province of British Columbia, Pollution Control Branch (1973 - 1974)

Patents

- Mazza; Giuseppe, Gao; Lei, Oomah; B. Dave, O'Connor; Donald, Crowe; Brian. "Functional, water-soluble protein-fibre products from grains". 07/19/2001. U.S. Patent No. 6,261,629.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennestad; Gordon, Berlin; Alex, MacLachlan; John Ross. "Continuous counter-current organosolv processing of lignocellulosic feedstocks," 12/16/08, U.S. Patent No. 7,465,791.
- Berlin; Alex, Pye; Edward Kendall, O'Connor; Donald, "Concurrent saccharification and fermentation of fibrous biomass," 11/15/11, U.S. Patent No. 8,058,041.

- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma; Raymond. Continuous counter-current organosolv processing of lignocellulosic feedstocks. 6/05/12, U.S. Patent No. 8,193,324.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma. Continuous counter-current organosolv processing of lignocellulosic feedstocks. 7/24/12, U.S. Patent No. 8,227,004.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma. Modular system for organosolv fractionation of lignocellulosic feedstock. 10/09/2013. U.S. Patent 8,528,463.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma. Continuous counter-current organosolv processing of lignocellulosic feedstocks. US Patent 8,772,427.

Peer Reviewed Papers

- Vuksan, V., Jenkins, D. J., Vidgen, E., Ransom, T. P., Ng, M. K., Culhane, C. T., & O'Connor, D. 1999. A novel source of wheat fiber and protein: effects on fecal bulk and serum lipids–. The American journal of clinical nutrition, 69(2), 226-230.
- O'Connor, D., Esteghlalian, A.R., Gregg, D.J. and Saddler, J.N. 2003. Carbon Balance of Ethanol from Wood: The effect of Feedstock Source in Canada. The Role of Boreal Forests and Forestry in the Global Carbon Budget. pp. 289-296 (Proceedings of the International Science Conference, Edm. Alta. May 2000).
- Hünerberg, M., Little, S.M., Beauchemin, K.A., McGinn, S.M., O'Connor, D., Okine, E.K., Harstad, O.M., Kröbel, R. and McAllister, T.A., 2014. Feeding high concentrations of corn dried distillers' grains decreases methane, but increases nitrous oxide emissions from beef cattle production. *Agricultural Systems*, *127*, pp.19-27.
- Chen, R., Qin, Z., Han, J., Wang, M., Taheripour, F., Tyner, W., O'Connor, D. and Duffield, J., 2018. Life cycle energy and greenhouse gas emission effects of biodiesel in the United States with induced land use change impacts. *Bioresource technology*, *251*, pp.249-258.

Education

- Bachelor of Applied Science, Mechanical Engineering, University of British Columbia (1973)

Professional Memberships

- Association of Professional Engineers and Geoscientists of British Columbia
- Association of Professional Engineers of Ontario
- Society of Automotive Engineers

Awards

- Canadian Renewable Fuels Association. Outstanding Dedication to the Advancement of Renewable Fuels in Canada. 2007.

APPENDIX "E"

Indirect Land Use Comments
April 23, 2018
By Thomas Darlington, Air Improvement Resource Inc.
Donald O'Connor, (S&T)[2] Consultants Inc.

ARB Failed to Update Indirect Land Use Emissions in the LCFS

The carbon intensities of biofuels include estimated emissions for indirect land use changes, generally referred to as "ILUC." Including estimates of these emissions in the carbon intensities of biofuels by ARB has been controversial, because the ILUC estimates for biofuels are very uncertain, and require a myriad of input information and different models to estimate. In prior efforts to determine ILUC, the input information needed to make these estimates was not available, and the models used to make these estimates were in their infancy.

ILUC emissions should not have been included in the LCFS by ARB in the first place, as the science has not matured to the point where it included most of the significant input drivers. For example, the ILUC estimates for biofuels used by ARB in the current and previous LCFS regulation do not include any effects for multi-cropping or the use of idle cropland. These and other factors have been pointed out to ARB since the advent the LCFS regulations. Economists have been developing methods of including these factors in ILUC estimates, and their inclusion into ILUC estimates has had a dramatic effect at reducing initial biofuel ILUC estimates. B4-108

Indeed, it is now widely recognized that early efforts to calculate ILUC were significantly overstated. As the methods for estimating these emissions have started to mature somewhat, the ILUC estimates for various biofuels have fallen significantly. For example, an early estimate of ILUC for corn ethanol was 106 g/MJ.[1] ARB's first estimate of the ILUC of corn ethanol was 30 g/MJ.[2] The ILUC of corn ethanol in the current regulation is 19.8 g/MJ.[3]

Substantial evidence no longer supports an ILUC of 19.8 g/MJ for corn ethanol. The consensus among technical experts is that these ILUC values remain overstated, and should be further reduced. Specifically, current estimates for the ILUC of corn ethanol in the U.S. range from 7.8-12 g/MJ.[4,5]

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[1] *Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land-Use Change*, Searchinger, T., Heimlich, R., Houghton, R.A., Dong, F., Elobeid, A., Fabiosa, J., Tokgoz, S., hayes, D., Yu, T., Science, 29 Feb 2008: Vol. 319, Issue 5867, pp. 1238-1240DOI: 10.1126/science.1151861
[2] Final Regulation Order for Low Carbon Fuel Standard, January 12, 2010, Table 6, page 47, https://www.arb.ca.gov/regact/2009/lcfs09/finalfro.pdf
[3] Final Regulation Order for Low Carbon Fuel Standard, Table 5, page 60, https://www.arb.ca.gov/regact/2015/lcfs2015/lcfsfinalregorder.pdf
[4] Argonne GREET2016 Model, https://greet.es.anl.gov/

Despite this new data, in the proposed LCFS amendments, ARB has updated the direct emission estimates such as the farming and fertilizer emissions, but failed to update the indirect estimates. The ILUC estimates are a very significant proportion of total emissions for biofuels. For example, the total carbon intensity for corn ethanol is now around 68 g/MJ, depending on various inputs from the corn ethanol plant and the distance of that plant from California. The ILUC estimate for corn ethanol is 19.8 g/MJ, which is 30% of the total carbon intensity. ARB has therefore taken a "piecemeal" approach to updating the carbon intensities to the various biofuels. With respect to updating the ILUC estimates, the ISOR states:

> Staff has not observed sufficient evidence in the literature to justify modifying the LUC CI values for the proposed regulation.[6]

This statement is simply not true. Growth Energy, in its comments on the existing regulation, referenced significant work by the Babcock and Iqbal at the University of Iowa that showed significantly less global land conversions due to biofuel policies than previous thought and estimated by the ARB staff. [7,8] Their analysis showed that land "intensification", that is, the use of existing cropland through multi-cropping and the use of idle land, was much more prevalent than land "extensification", where land such as forest is converted to cropland. ARB's ILUC estimates were primarily based on land extensification. Growth Energy also recommended methods of incorporating UI's analysis into ARB's estimates, and developed preliminary estimates of ILUC using the Babcock/Iqbal work. B4-108 cont.

The work by Babcock/Iqbal was also reviewed extensively by Global Trade Analysis Project (GTAP) researchers at the University of Purdue. The GTAP economic general equilibrium model is used by ARB to estimate ILUC values for biofuels for the LCFS. Purdue researchers used the Babcock/Iqbal methods and data to update the GTAP model, and the Purdue researchers also updated many other significant factors in the GTAP model, including updating the GTAP model database from calendar year 2004 to calendar year 2011.[9] Their work was published in a peer-reviewed journal publication in July of 2017.[10] Their work showed that, using ARB's AEZ-EF model in conjunction with GTAP to estimate emissions associated with the various land use changes, corn ethanol ILUC dropped from 23.3 g/MJ to 12 g/MJ, with the

[5] *The impact of considering land intensifications and updated data on biofuels land use change and emissions estimates,* Figure 4, F. Taheripour, X. Zhao, and W. Tyner, Biotechnology for Biofuels, DOI.1186/s13068-017-0877-y, July 2017
[6] Initial Statement of Reasons for LCFS, Page III-86.
[7] Growth Energy's Response to the Notices of Public Hearings Dated December 16, 2014 2015 Cal. Reg. Notice Reg. 13, 45 (January 2, 2015), February 17, 2015, Appendix A.
[8] Using Recent Land Use Changes to Validate Land use Change Models", Babcock and Iqbal, Staff Report 14-SR- 109, Center for Agriculture and Rural Development, Iowa State University, www.card.iastate.edu.
[9] The current ARB ILUC estimates are based on the 2004 calendar year database.
[10] *The impact of considering land intensifications and updated data on biofuels land use change and emissions estimates,* F. Taheripour, X. Zhao, and W. Tyner, Biotechnology for Biofuels, DOI.1186/s13068-017-0877-y, July 2017.

incorporation of (1) land intensification effects, and (2) the change to the 2011 database.[11] The reduction in corn ethanol ILUC associated with these model updates is 48%. Assuming that this percent reduction in ILUC obtained by Purdue with the two major model modifications can be applied to ARB's current ILUC value for corn ethanol of 19.8, gives a value of 10.3 g/MJ. Therefore, if Staff had used the available updated GTAP model to estimate new ILUC values for biofuels using its 30 sensitivity scenarios, it is likely ARB would have developed an estimate of around 10g/MJ for corn ethanol. There would have been significant changes in the ILUC values for other biofuels as well, since land intensification and the change in database would likely have affected all biofuel feedstocks.

The technical documents supporting the ISOR and the EA also do not recognize ongoing efforts by technical experts to resolve known issues relating to the overstatement of the ILUC value for corn ethanol, and to incorporate more recent facts into these analysis. For example, the current ILUC for corn ethanol does not reflect accurate facts because it is based on year 2011 conditions, which correspond to a drought year in the US which negatively impacted crop yields. This is important because higher yields mean that less land use change is required to satisfy the new demand resulting in lower ILUC values. The 2011 corn yield was 146.8 bu/acre, which was actually lower than the 2004 yield of 160.3 bu/acre and one of the reasons why the ILUC emissions went up when the 2011 database was used. The 2017 corn yield was 176.6 bu/acre. B4-108 cont.

The GTAP team is also investigating the response of the livestock sector to increased biofuel production in the model to ensure that the model is consistent with the observed recent changes in that sector. In particular, there has been a major shift in livestock production in the last 40 years in the US from beef to poultry. Because of the much lower land requirements of poultry than beef, much agricultural land has been freed up for other agricultural uses, and this has led to lower land use transformation than previously thought.[12]

Therefore, our conclusion is that (1) the existing ILUC value for corn ethanol of 19.8 g/MJ is no longer supported by substantial evidence, (2) the literature demonstrates the ILUC values should be updated in time for the proposed amendments to the LCFS regulation, and (3) if the values had been updated by ARB, they would have been much lower than the values from the previous regulation.

[11] Purdue ran a single scenario to estimate these values. For the current regulation, ARB ran 30 scenarios with varying inputs and averaged the 30 results to obtain the 19.8 g/MJ for corn ethanol.
[12] *Technological progress in US agriculture: Implications for biofuel production*, Taheripour, F., Department of Agricultural Economics, Purdue University, presented at National Biodiesel Board Webinar, March 15, 2018.

Curriculum Vitae

For

Thomas Darlington

And

Donald O'Connor

Thomas L. Darlington
President, Air Improvement Resource Inc.

Profile

Thomas L. Darlington is President of Air Improvement Resource, a company formed in 1994 specializing in mobile source emission modeling. He is an internationally recognized expert in mobile source emissions modeling, lifecycle analysis, and land use modeling.

Professional Experience

1994-Present	President, Air Improvement Resource
1993-1994	Director, Mobile Source Programs, Systems Application International
1989-1994	Senior Engineer, General Motors Corporation, Environmental Activities
1988-1989	Senior Project Engineer, Detroit Diesel Corporation
1979-1988	Project Manager, U.S. EPA, Ann Arbor, Michigan

Recent Major Projects

- Provided numerous OMEGA outputs to The Alliance for their review of the 2022-2025 GHG standards
- Participating on behalf of Growth Energy in EPA's MOVES model development stakeholder meetings
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- Developed Life Cycle reports and complete applications for 8 plants for the California Low Carbon Fuel Standard
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- Reviewed the land use impacts of the RFS2 from EPA, including the notice of Proposed Rule, Regulatory Impact Analysis, and approximately one hundred documents in the rulemaking docket.

Air Improvement Resource, Inc. 10820 Boyce Rd, Chelsea, Michigan 48118
Phone: 248-921-5096

- Completed a land use study for Renewable Fuels Association and reviewed California Air Resource Board's Initial Statement of Reasons for the Low Carbon Fuel Standard
- Represented three stakeholders in the recent development of the ARB Predictive Model for reformulated gasoline in California (Alliance of Automobile Manufacturers, Renewable Fuels Association and Western States Petroleum Association)
- Represented two stakeholders in EPA's development of the MOVES on-highway emissions model (Alliance of Automobile Manufacturers and Engine Manufacturers Association)
- Developed the effects of ethanol permeation on on-highway and off-highway mobile sources in California and other states for the American Petroleum Institute
- Studied gasoline and diesel fuel options for Southeast Michigan (for SEMCOG, API and Alliance of Automobile Manufacturers)

Recent Publications

Darlington, T., Herwick, G., Kahlbaum, D., and Drake, D., "Modeling the Impact of Reducing Vehicle Greenhouse Gas Emissions with High Compression Engines and High Octane Low Carbon Fuels," SAE 2017-01-0906, 2017, doi: 10.4271/2017-01-0906.

Darlington, T., Kahlbaum, D., Van Hulzen, S., and Furey, R., "Analysis of EPAct Emission Data Using T70 as an Additional Predictor of PM Emissions from Tier 2 Gasoline Vehicles", SAE Technical Paper 2016-01-0996, 2016, doi: 10.4271/2016-01-0996.

"Study of Transportation Fuel Life Cycle Analysis: Review of Economic Models Used to Assess Land Use Effects", CRC-E-88-3, July 2014.

"Land Use Change Greenhouse Gas Emissions of European Biofuel Policies Utilizing the Global Trade Analysis Project Model", Darlington, Kahlbaum, O'Connor, and Mueller, August 30, 2013.

"A Comparison of Corn Ethanol Lifecycle Analyses: California Low Carbon Fuels Standard (LCFS) Versus Renewable Fuels Standard (RFS2)", June 14, 2010. Renewable Fuels Association and Nebraska Corn Board. This study compared and contrasted the corn ethanol lifecycle analyses performed by both CARB (as a part of the LCFS) and the EPA (as a part of RFS2).

"Review of EPA's RFS2 Lifecycle Emissions Analysis for Corn Ethanol", September 25, 2009. Conducted for Renewable Fuels Association. This study reviewed EPA's land use GHG emissions assessment for corn ethanol, including the FASOM and FAPRI models and Winrock land-use types converted and emission factors by ecosystem type. The study made many recommendations for improving the land-use and emissions modeling.

Air Improvement Resource, Inc. 10820 Boyce Rd, Chelsea, Michigan 48118
Phone: 248-921-5096

"Review of CARB's Low Carbon Fuel Standard Proposal", April 15, 2009. Conducted for Renewable Fuels Association. This study reviewed CARB's analysis of land use emissions using GTAP6 and CARB's overall lifecycle emissions for corn ethanol. This study made many recommendations for improving the land use and lifecycle emissions of corn ethanol.

"Emission Benefits of a National Clean Gasoline", August 2008. Conducted for the Alliance of Automobile Manufacturers. This study evaluated the nationwide criteria pollutant emission reductions of a national clean gasoline standard.

"Land Use Effects of Corn-Based Ethanol", February 25, 2009. Conducted for Renewable Fuels Association. This study evaluates possible land use changes and GHG emissions associated with these land use changes as a result of the renewable fuel standard mandated 15 billion gallons of corn ethanol required by calendar year 2015. The study utilized projections of land use in the US and rest of world performed by Informa Economics, LLC, as well as newer estimates of the land use credits of co-products produced by ethanol plants to evaluate possible land use changes.

"On-Road NOx Emission Rates From 1994-2003 Heavy-Duty Trucks", SAE2008-01-1299, conducted for the Engine Manufacturers Association. This study examined manufacturers consent decree emissions data to determine on-road NOx emission rates, and deterioration in emissions from heavy-duty vehicles. (Peer reviewed publication)

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act - Part 2: CO2 and GHG Impacts", SAE2008-01-1853, conducted for the Alliance of Automobile Manufacturers. This paper evaluated the comparison of greenhouse gases from cars and light trucks in the US under both the Federal and California GHG policies. (Peer reviewed publication)

"Effectiveness of the California Light Duty Vehicle Regulations as Compared to Federal Regulations", June 15, 2007. Conducted with NERA Economic Consulting and Sierra Research for The Alliance of Automobile Manufacturers. This study compares the emission benefits of the California and Federal light duty vehicle regulations for HC, CO, NOx, PM, SOx, and Toxics taking into account the difference in emission standards, new vehicle costs and its effect on fleet turnover, new vehicle fuel economy and its effect on vehicle miles traveled, and other factors. Both the EPA MOBILE6 and ARB EMFAC on-road emissions models were used to estimate changes in emissions inventories.

"The Case for a Dual Tech 4 Model Within the California Predictive Model", May 20, 2007. Conducted with ICF International and Transportation Fuels Consulting for the Renewable Fuels Association (RFA). This study developed separate emissions vs fuel property models for lower and higher Tech 4 (1986-1995) vehicles, and showed that utilizing this alternative Predictive Model would result in a higher compliance margin for fuels containing higher volumes of ethanol. It was thought that this could lead to higher ethanol concentrations in the state, but even if the dual model is not used, it is a better representation of the 2015 inventory than the ARB single model.

Air Improvement Resource, Inc. 10820 Boyce Rd, Chelsea, Michigan 48118
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"Updated Final Report, Effects of Gasoline Ethanol Blends on Permeation Emissions Contribution to VOC Inventory From On-Road and Off-Road Sources, Inclusion of E-65 Phase 3 Data and Other Updates", June 20, 2007. Conducted for the American Petroleum Institute. This report updates the earlier March 3, 2005 report for API utilizing data collected by CRC and others since of the time of the earlier report.

Final Report, Development of Technical Information for a Regional Fuels Strategy, February 28, 2006. Conducted for the Lake Air Directors Consortium (LADCO). This report provided guidance to the LADCO states (Midwestern states) concerning how to model different types of fuel control programs (in particular) using EPA mobile source models, and how to set up the baseline input files so that results are consistent between the different states.

"Emission Reductions from Changes to Gasoline and Diesel Specifications and Diesel Engine Retrofits in the Southeast Michigan Area", February 23, 2005. Conducted for the Southeast Michigan Council of Governments (SEMCOG), the Alliance of Automobile Manufacturers, and the American Petroleum Institute. This study examined the on-road and off-road emission benefits of many different possible gasoline and diesel fuel specifications that the state could adopt to help meet the 8-hour ozone standards. This study formed the basis for the state's move to lower RVP summer gasoline.

"Examination of Temperature and RVP Effects on CO Emissions in EPA's Certification Database, Final Report", CRC Project No. E-74a, April 11, 2005. Conducted for the Coordinating Research Council. This study compared CO vs temperature results from the MOBILE6 model to the certification data, and recommended further testing, which is being conducted by the CRC at this time.

"Effects of Gasoline Ethanol Blends on Permeation Emissions Contribution to VOC Inventory From On-Road and Off-Road Sources" March 3, 2005. Conducted for the American Petroleum Institute (API). Using data from the CRC-E-65 program, and data collected by the California EPA and Federal EPA, this study estimated the impacts of ethanol use on increasing permeation VOC emissions from on-road vehicles, off-road equipment and vehicles, and from portable containers. Emission inventory estimates were made for a number of geographical areas including the state of California, and results showed that the permeation effect increases anthropogenic VOC inventories by 2-4%.

Review of EPA Report "A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions", February 11, 2003. Conducted for the American Petroleum Institute. This study critically examined the methods that EPA used to develop the impacts of biodiesel fuels on HC, CO, NOx, and PM emissions.

"Well-To Wheels Analysis of Advanced Fuel/Vehicle Systems – A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions", May 2005. Conducted for General Motors Corporation, with Argonne National Labs. This study examined many different well to wheels pathways for various fuels, and their impacts on GHG and criteria pollutant emissions.

Air Improvement Resource, Inc. 10820 Boyce Rd, Chelsea, Michigan 48118
Phone: 248-921-5096

"Potential Delaware Air Emission Impacts of Switching From MTBE to Ethanol in the Reformulated Gasoline Program", May 26, 2005. Conducted for Lyondell Chemical Company. This study examined the HC, CO, and NOx impacts of switching from MTBE to ethanol.

"Potential Massachusetts Air Emission Impacts of Switching From MTBE to Ethanol in the Reformulated Gasoline Program" June 17, 2005. Conducted for Lyondell Chemical Company. This study is similar to the Delaware study above.

"Potential Maryland Air Emission Impacts of a Ban on MTBE in the Reformulated Gasoline Program", October 18, 2005. Conducted for Lyondell Chemical Company. This study is similar to the Delaware study above.

"MOBILE6.2C with Ethanol Permeation and Ethanol NOx Effects", February 8, 2005. Conducted for Health Canada. This study modified the MOBILE6.2C model for ethanol permeation VOC and ethanol NOx effects.

Education

B. Sc., (Materials and Metallurgical Engineering), University of Michigan, Ann Arbor, 1979
Post Graduate Courses (Business Administration), University of Michigan, Ann Arbor, 1982

Donald Victor O'Connor, P. Eng.

Summary

An innovative, achievement oriented business leader with over 40 years experience with energy and environmental issues in Canada. Successfully developed and commercialized environmentally sound energy alternatives.
Background includes:

- Development of the GHGenius life cycle assessment model for energy systems.
- Developing Canada's largest alternative fuel retailing program.
- Establishment of the ethanol industry in Western Canada, from manufacturing to retailing. Extensive experience with production of biofuels.
- Detailed knowledge of fuels and the fuels industry. Technical expertise regarding the utilization of methanol, ethanol, natural gas, propane, hydrogen, gasoline and diesel fuels.
- Developing objectives, strategy and tactics in highly competitive manufacturing and retail industries.

Professional Experience

(S&T)² Consultants Inc. (1998-2018)

President

The firm specializes in energy and environment issues. (S&T)² helps corporations with business development strategies concerning new energy markets and products and it helps governments understand the business, energy and environmental issues of new energy pathways.
Mr. O'Connor has recently provided strategic advice on fuels, transportation issues, and greenhouse gas emissions to a number of Provincial governments, several Canadian Federal Government departments, and international agencies and governments. Mr. O'Connor has also consulted for a number of companies developing new technologies for alternative fuelled vehicles and companies developing new transportation fuel processes and facilities.

Projects have included:

- Development of the GHGenius life cycle assessment model
- Development of the Ontario Ethanol Growth Fund. Led to the establishment of 50% of the Canadian ethanol production capacity.
- Analysis of the US EPA RFS program for the National Biodiesel Board. Resulted in soybean biodiesel passing the GHG emission threshold established by the US Congress.
- Establishment of the qualifying criteria for biofuels under the Alberta RFS program.
- Proposed and participated in the development of a novel, patented process for the production of ethanol from woody lignocellulosic feedstock. Five patents granted.
- Provided guidance and recommendations for the establishment of a biofuels program for the Government of Peru.
- Provided project development services for the development and construction of western Canada's largest fuel ethanol plant.

Mohawk Canada Limited (1981 – 1998)

Mohawk was Western Canada's largest independent automotive fuel retailer offering environmentally responsible fuels and lubricants through 300 retail and bulk facilities. Mohawk also manufactures re-refined lubricants from used oil, and ethanol, distillers' grains and Fibrotein from grain.

President, COO, and Director, Mohawk Products Ltd. (1997 – 1998)
President, COO, and Director, Mohawk Lubricants Ltd. (1992 – 1998)
Vice President, Supply and Manufacturing (1989 – 1998)
Various positions in R&D, manufacturing and supply (1981-1989)

Donald Victor O'Connor, P. Eng.

Responsibilities:

- Led and managed three business units simultaneously. These units manufactured lubricants from used oil, processed grain into ethanol and human and animal foods, and the corporate supply function covering all aspects of fuels' development, supply and distribution, and core supplier relationships for convenience goods and corporate services. Recommended objectives, strategy and tactics consistent with the organization's values to achieve corporate vision.

Accomplishments:

- Contributed to the development of a vision and unique corporate positioning that allowed the company to increase its market share by 50% over five years;
- Initiated and led the successful introduction of several new or differentiated alternative fuels to the market (Natural Gas, M85, Ethanol blends (Regular Plus and Premium Plus), and premium diesel fuels (Diesel with ECA and Diesel Max);
- Led the turnaround of used oil re-refining business by doubling production and sales over a four-year period. Increased bottom line by 500% and made the operation the most profitable of its kind in the world.
- Introduced a strategic sourcing program throughout the organization.

Additional Professional Activities

- Advisory Committee. ILUC Quantification Study of EU Biofuels. GLOBIOM Model ILUC project.
- Canadian expert on GHG emissions and indirect effects to ISO TC 248 developing ISO 13065.
- Expert Working Group on Indirect Effects. California Air Resources Board. 2010
- Canadian Biomass Innovation Network. External Advisory Panel. 2005-2010.
- Director, B.C. Buildings Corporation. 2000-2002
- Co-Chair 1999-2001. Member, Executive Committee on Cleaner Technology Vehicles (Minister's Committee, B.C. Environment) (1995 - 2001)
- Director, Pound-Maker Adventures (1990 - 1998) An integrated ethanol plant cattle feeding operation in Saskatchewan.
- Director, Canadian Renewable Fuels Association (1990 – 1998, 2000-2002)
- Member, Environment Advisory Committee, Vancouver Foundation (2001-2003)
- Member, Ethanol BC Board (2000-2010)
- Member, Bio-based Products R&D Advisory Council, BIOCAP Canada, (2002-2003)
- Member, National Advisory Committee on Bioenergy (1984 - 1990)
- Member, Efficiency and Alternative Energy Committee, Minister's National Advisory Council to CANMET (1990 - 1994)
- Chair, Ethanol Program Advisory Committee, Agriculture and Agrifood Canada (1992 - 1997)
- Canadian Petroleum Products Institute, Western Division Management Committee (1996 - 1998)
- Numerous presentations on alternative fuels at National and International conferences.

Employment

- Manager, Energy and Environmental Technology, B.H. Levelton & Associates Ltd. Consulting Engineers (1974 - 1981)
- Air Engineer, Province of British Columbia, Pollution Control Branch (1973 - 1974)

Patents

- Mazza; Giuseppe, Gao; Lei, Oomah; B. Dave, O'Connor; Donald, Crowe; Brian. "Functional, water-soluble protein-fibre products from grains". 07/19/2001. U.S. Patent No. 6,261,629.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennestad; Gordon, Berlin; Alex, MacLachlan; John Ross. "Continuous counter-current organosolv processing of lignocellulosic feedstocks," 12/16/08, U.S. Patent No. 7,465,791.
- Berlin; Alex, Pye; Edward Kendall, O'Connor; Donald, "Concurrent saccharification and fermentation of fibrous biomass," 11/15/11, U.S. Patent No. 8,058,041.

- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma; Raymond. Continuous counter-current organosolv processing of lignocellulosic feedstocks. 6/05/12, U.S. Patent No. 8,193,324.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma. Continuous counter-current organosolv processing of lignocellulosic feedstocks. 7/24/12, U.S. Patent No. 8,227,004.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma. Modular system for organosolv fractionation of lignocellulosic feedstock. 10/09/2013. U.S. Patent 8,528,463.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma. Continuous counter-current organosolv processing of lignocellulosic feedstocks. US Patent 8,772,427.

Peer Reviewed Papers

- Vuksan, V., Jenkins, D. J., Vidgen, E., Ransom, T. P., Ng, M. K., Culhane, C. T., & O'Connor, D. 1999. A novel source of wheat fiber and protein: effects on fecal bulk and serum lipids–. The American journal of clinical nutrition, 69(2), 226-230.
- O'Connor, D., Esteghlalian, A.R., Gregg, D.J. and Saddler, J.N. 2003. Carbon Balance of Ethanol from Wood: The effect of Feedstock Source in Canada. The Role of Boreal Forests and Forestry in the Global Carbon Budget. pp. 289-296 (Proceedings of the International Science Conference, Edm. Alta. May 2000).
- Hünerberg, M., Little, S.M., Beauchemin, K.A., McGinn, S.M., O'Connor, D., Okine, E.K., Harstad, O.M., Kröbel, R. and McAllister, T.A., 2014. Feeding high concentrations of corn dried distillers' grains decreases methane, but increases nitrous oxide emissions from beef cattle production. *Agricultural Systems*, *127*, pp.19-27.
- Chen, R., Qin, Z., Han, J., Wang, M., Taheripour, F., Tyner, W., O'Connor, D. and Duffield, J., 2018. Life cycle energy and greenhouse gas emission effects of biodiesel in the United States with induced land use change impacts. *Bioresource technology*, *251*, pp.249-258.

Education

- Bachelor of Applied Science, Mechanical Engineering, University of British Columbia (1973)

Professional Memberships

- Association of Professional Engineers and Geoscientists of British Columbia
- Association of Professional Engineers of Ontario
- Society of Automotive Engineers

Awards

- Canadian Renewable Fuels Association. Outstanding Dedication to the Advancement of Renewable Fuels in Canada. 2007.

APPENDIX "F"

Comments on the Simplified Corn and Sugarcane Calculators
April 23, 2018
By Donald O'Connor, (S&T)² Consultants Inc.

Starch Calculator

The simplified starch calculator that CARB released as part of the rule making process on March 6, 2018 appears to be functioning properly. The incorrect N_2O emission factor for corn that was presented in the version released in November has been corrected. B4-109

We were able to confirm that all of the emission factors used in the calculator came from the CA GREET 3.0 model. There is one small issue with the emission factors for ethanol transportation. In GREET there is a small amount of electricity that is used in the transportation and distribution calculations that is independent of the mode of transport. This is essentially the power to load the truck or rail car. The emissions for the power are determined by the region used for the electric power mix. For starch ethanol most of the trucking emissions are likely to be in California but the emission factor is developed using US average power. The value used is 0.6366 g CO_2eq/gal-mile. The California value is 0.6287 g CO_2eq/gal-mile. The difference is small but as shown below the lower value is being used for sugarcane ethanol. B4-110a

The GHG emissions for corn ethanol are about 49 g/MJ without ILUC and 68 with ILUC. Individual plants with vary. This is significantly lower than the existing Tier 1 calculator that has values of about 83 g/MJ with ILUC. B4-110b

The emission calculations of the sorghum ethanol are 4 g/MJ higher than corn ethanol and the difference is all in the feedstock emission area. B4-110c

There are 25 hidden sheets in the model. There does not appear to be any information transferred in from the hidden sheets which suggests that these sheets could and should be removed. B4-110d

Also rows 85 to 87 on the EF Tables sheet are not used and should be deleted.

Sugarcane Ethanol Calculator

The sugarcane ethanol calculator needs to be cleaned up. There are a lot of calculations on sheets EF Tables and EF General that take emissions in g/MJ from CA GREET and then convert the emissions to g/tonne, when the g/tonne emission factor can be taken directly from CA GREET. For many of the calculations the conversion of VOC and CO emissions to CO_2eq is done with rounded emission factors rather than the actual values used in CA GREET. This leads to small differences in the emission factors and the potential for errors since the GWP conversion factors are hard coded in the calculator. We found at least one error in coding where the wrong conversion factor was used. B4-111a

There is one sheet, Feasibility Report 1, that is hidden and it should be visible for full transparency. B4-111b

1

The critical parameters are in rows 131 and 142 on the Calculator sheet. These emission factors should all be the same as the values in CA GREET 3.0. When CA GREET 3.0 is used it needs to be set up on the Region Selection sheet. Setting the electricity to the Brazilian mix in cells B8 and E8 is obvious but the appropriate setting for the crude oil and natural gas setting is not obvious. The natural gas selection does not have an impact on the emission factor. The crude oil selector has a very small impact of the emission factors. We have set the regions to Brazil for the electricity and the US parameters for natural gas and crude oil. This appears to be what CARB did. B4-111c

As noted above, in the calculator the conversion of CO and VOC to GHG emissions is generally hard code and the factors used have been rounded to two decimal points. The calculator underestimates the CO emissions and overestimates the VOC emissions as shown below. B4-111d

	CA GREET	Calculator
	GWP Conversion	
VOC	3.1167	3.12
CO	1.5714	1.57

Each of the emission factors in row 131 is discussed below.

Sugarcane Agriculture & Farming Impacts

The emission factors from the calculator and from CA GREET are compared in the following table.

	CA GREET	Calculator
	g CO_2eq/tonne cane	
Farming	8,377	7,819
Fertilizer	8,394	8,393
N_2O	11,279	11,279
Total	28,049	27,491

B4-112

The farming emissions in the calculator appear to include VOC emissions from bulk terminal that is not used in CA GREET and have applied a GWP factor of 1.57 instead of 25 to the methane emissions (AP 39 on the EF Tables Sheet). It is not clear what the bulk terminal emissions would be for sugarcane farming but the impact is only 24 g/tonne but the methane GWP has an impact of about 580 g/tonne (2%) and accounts for most of the understatement of emissions.

Cane & Filtercake Transport

The emission factor for the cane and filtercake emissions is a dynamic calculation. It uses emission data on tonne-mile basis from CA GREET and then multiplies it by the miles, adds the filtercake transport emissions calculated in a similar factor and then applies it to the tonnes of cane transported. The emission factor therefore changes when the miles transported changes. B4-113

The model uses incorrect emission factors from CA GREET. On the EF Tables sheet the composite emission factor is calculated in rows 9 to 13, columns C to H. The emission factors in column C for the HDD truck are not the same as they are in CA GREET as shown in the following table. B4-113 cont.

	CA GREET	Calculator
	HDD (grams/ton-mile cane transported)	
VOC	0.083	0.038
CO	0.275	0.131
CH_4	0.673	0.180
N_2O	0.001	0.002
CO_2	289	136.45
GHG	307	141

The calculator again understates the emission factor for sugarcane ethanol, in this case by more than a factor of two.

Straw Burning Emissions

The straw burning emissions are close and the difference is caused by the GWP conversion factors for VOC and CO. B4-114

	CA GREET	Calculator
	Emissions per tonne of cane	
VOC	1,499.4	1,499.4
CO	19,706.4	19,706.4
CH_4	578.3	578.3
N_2O	15.0	15.0
CO_2	-37,230.8	-37,230.8
GHG	17,336.3	17,313.1

Net Surplus Cogenerated Electricity Credit

The emission credit provided for the net (after T&D losses) excess power is the same value as is used for power generation in Brazil. B4-115

Ethanol Production Emissions

The ethanol production emission factor in the simplified calculator is much lower than it is in CA GREET. In the simplified calculator it is the sum of emissions from residual oil, lime use, and the non-biogenic emissions of bagasse combustion.

CA GREET included emissions from burning straw as well as burning bagasse. When the straw burning emissions are removed from CA GREET we get the values in the following table. It is not clear where the errors in fuel oil and lime are in the calculator as they are fixed values. The fuel oil emissions are from an assumption that 10% of the lubricants B4-116

3

are combusted. It is much more likely that 100% of the spent lubricants are either burned or used for dust suppression where they are eventually oxidized.

	CA GREET	Calculator
	Emissions per gallon of ethanol	
Fuel oil	2.99	9.9
Lime	37.35	48.8
Bagasse combustion	175.16	168.3
Total	222.5	227.0

B4-116 cont.

The simplified calculator asks for the amount of externally acquired bagasse in column I of the Calculator tab but this value does not go anywhere. However the power that is produced from imported bagasse is excluded from the electricity credit calculation.

Truck Transport Emissions

The same emission factor is used for truck transport in Brazil and in California. This should not be the case as there is a different power mix in the two regions. The Brazilian results are shown in the following table.

	CA GREET	Calculator
	Emissions per mmBTU-mile	
VOC	0.0022	0.0022
CO	0.0073	0.0073
CH_4	0.0179	0.0180
N_2O	0.0000	0.0000
CO_2	7.6835	7.6757
GHG	8.1616	8.1532
GHG, g CO_2/gallon	0.623	0.622

B4-117

The difference is due to the rounding of the GWP for VOC and CO. The larger issue is that these are not the same emission factors used for the corn ethanol calculator even for the California portion of the transport.

Anhydrous Ethanol Ocean Transport Emissions

The comparison of the ocean transport emission factors is presented below. The differences are again due to the GWP rounding in the calculator.

	CA GREET	Calculator
	Emissions per mmBTU-mile	
VOC	0.0010	0.0010
CO	0.0022	0.0022
CH_4	0.0020	0.0020
N_2O	0.0000	0.0000
CO_2	1.0833	1.0831

B4-118

GHG	1.1408	1.1472
GHG, g CO_2/gallon	0.0871	0.0876

B4-118 cont.

Summary

The development of the emission factors used in the sugarcane calculator is much more complicated than it needs to be. There are two significant errors in the calculator.

1. The farming emission factor is too low due to the use of 1.57 instead of 25 for the methane GWP. B4-120

2. The sugarcane transportation emissions are about half of what they should be due to the use of incorrect emission factors. B4-121

There are a number of other small errors due to the hard coding of truncated GWPs for CO and VOC. There are some inconsistencies between the emission factors used for this calculator and the starch ethanol calculator for exactly the same activity. B4-122

Curriculum Vitae

For

Donald Victor O'Conner, P. Eng

Donald Victor O'Connor, P. Eng.

Summary

An innovative, achievement oriented business leader with over 40 years experience with energy and environmental issues in Canada. Successfully developed and commercialized environmentally sound energy alternatives.
Background includes:

- Development of the GHGenius life cycle assessment model for energy systems.
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- Establishment of the ethanol industry in Western Canada, from manufacturing to retailing. Extensive experience with production of biofuels.
- Detailed knowledge of fuels and the fuels industry. Technical expertise regarding the utilization of methanol, ethanol, natural gas, propane, hydrogen, gasoline and diesel fuels.
- Developing objectives, strategy and tactics in highly competitive manufacturing and retail industries.

Professional Experience

$(S\&T)^2$ Consultants Inc. (1998-2018)

President

The firm specializes in energy and environment issues. $(S\&T)^2$ helps corporations with business development strategies concerning new energy markets and products and it helps governments understand the business, energy and environmental issues of new energy pathways.
Mr. O'Connor has recently provided strategic advice on fuels, transportation issues, and greenhouse gas emissions to a number of Provincial governments, several Canadian Federal Government departments, and international agencies and governments. Mr. O'Connor has also consulted for a number of companies developing new technologies for alternative fuelled vehicles and companies developing new transportation fuel processes and facilities.

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Mohawk was Western Canada's largest independent automotive fuel retailer offering environmentally responsible fuels and lubricants through 300 retail and bulk facilities. Mohawk also manufactures re-refined lubricants from used oil, and ethanol, distillers' grains and Fibrotein from grain.

President, COO, and Director, Mohawk Products Ltd. (1997 – 1998)
President, COO, and Director, Mohawk Lubricants Ltd. (1992 – 1998)
Vice President, Supply and Manufacturing (1989 – 1998)
Various positions in R&D, manufacturing and supply (1981-1989)

Donald Victor O'Connor, P. Eng.

Responsibilities:

- Led and managed three business units simultaneously. These units manufactured lubricants from used oil, processed grain into ethanol and human and animal foods, and the corporate supply function covering all aspects of fuels' development, supply and distribution, and core supplier relationships for convenience goods and corporate services. Recommended objectives, strategy and tactics consistent with the organization's values to achieve corporate vision.

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- Initiated and led the successful introduction of several new or differentiated alternative fuels to the market (Natural Gas, M85, Ethanol blends (Regular Plus and Premium Plus), and premium diesel fuels (Diesel with ECA and Diesel Max);
- Led the turnaround of used oil re-refining business by doubling production and sales over a four-year period. Increased bottom line by 500% and made the operation the most profitable of its kind in the world.
- Introduced a strategic sourcing program throughout the organization.

Additional Professional Activities

- Advisory Committee. ILUC Quantification Study of EU Biofuels. GLOBIOM Model ILUC project.
- Canadian expert on GHG emissions and indirect effects to ISO TC 248 developing ISO 13065.
- Expert Working Group on Indirect Effects. California Air Resources Board. 2010
- Canadian Biomass Innovation Network. External Advisory Panel. 2005-2010.
- Director, B.C. Buildings Corporation. 2000-2002
- Co-Chair 1999-2001. Member, Executive Committee on Cleaner Technology Vehicles (Minister's Committee, B.C. Environment) (1995 - 2001)
- Director, Pound-Maker Adventures (1990 - 1998) An integrated ethanol plant cattle feeding operation in Saskatchewan.
- Director, Canadian Renewable Fuels Association (1990 – 1998, 2000-2002)
- Member, Environment Advisory Committee, Vancouver Foundation (2001-2003)
- Member, Ethanol BC Board (2000-2010)
- Member, Bio-based Products R&D Advisory Council, BIOCAP Canada, (2002-2003)
- Member, National Advisory Committee on Bioenergy (1984 - 1990)
- Member, Efficiency and Alternative Energy Committee, Minister's National Advisory Council to CANMET (1990 - 1994)
- Chair, Ethanol Program Advisory Committee, Agriculture and Agrifood Canada (1992 - 1997)
- Canadian Petroleum Products Institute, Western Division Management Committee (1996 - 1998)
- Numerous presentations on alternative fuels at National and International conferences.

Employment

- Manager, Energy and Environmental Technology, B.H. Levelton & Associates Ltd. Consulting Engineers (1974 - 1981)
- Air Engineer, Province of British Columbia, Pollution Control Branch (1973 - 1974)

Patents

- Mazza; Giuseppe, Gao; Lei, Oomah; B. Dave, O'Connor; Donald, Crowe; Brian. "Functional, water-soluble protein-fibre products from grains". 07/19/2001. U.S. Patent No. 6,261,629.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennestad; Gordon, Berlin; Alex, MacLachlan; John Ross. "Continuous counter-current organosolv processing of lignocellulosic feedstocks," 12/16/08, U.S. Patent No. 7,465,791.
- Berlin; Alex, Pye; Edward Kendall, O'Connor; Donald, "Concurrent saccharification and fermentation of fibrous biomass," 11/15/11, U.S. Patent No. 8,058,041.

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- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma. Continuous counter-current organosolv processing of lignocellulosic feedstocks. 7/24/12, U.S. Patent No. 8,227,004.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma. Modular system for organosolv fractionation of lignocellulosic feedstock. 10/09/2013. U.S. Patent 8,528,463.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma. Continuous counter-current organosolv processing of lignocellulosic feedstocks. US Patent 8,772,427.

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- Vuksan, V., Jenkins, D. J., Vidgen, E., Ransom, T. P., Ng, M. K., Culhane, C. T., & O'Connor, D. 1999. A novel source of wheat fiber and protein: effects on fecal bulk and serum lipids–. The American journal of clinical nutrition, 69(2), 226-230.
- O'Connor, D., Esteghlalian, A.R., Gregg, D.J. and Saddler, J.N. 2003. Carbon Balance of Ethanol from Wood: The effect of Feedstock Source in Canada. The Role of Boreal Forests and Forestry in the Global Carbon Budget. pp. 289-296 (Proceedings of the International Science Conference, Edm. Alta. May 2000).
- Hünerberg, M., Little, S.M., Beauchemin, K.A., McGinn, S.M., O'Connor, D., Okine, E.K., Harstad, O.M., Kröbel, R. and McAllister, T.A., 2014. Feeding high concentrations of corn dried distillers' grains decreases methane, but increases nitrous oxide emissions from beef cattle production. *Agricultural Systems*, *127*, pp.19-27.
- Chen, R., Qin, Z., Han, J., Wang, M., Taheripour, F., Tyner, W., O'Connor, D. and Duffield, J., 2018. Life cycle energy and greenhouse gas emission effects of biodiesel in the United States with induced land use change impacts. *Bioresource technology*, *251*, pp.249-258.

Education

- Bachelor of Applied Science, Mechanical Engineering, University of British Columbia (1973)

Professional Memberships

- Association of Professional Engineers and Geoscientists of British Columbia
- Association of Professional Engineers of Ontario
- Society of Automotive Engineers

Awards

- Canadian Renewable Fuels Association. Outstanding Dedication to the Advancement of Renewable Fuels in Canada. 2007.

B_ECOENGINEERS1_B5

John Sens
18-3-3

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April 27th, 2018

The Honorable Mary Nichols, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Low Carbon Fuel Standard Extension Draft Regulation

Dear Chair Nichols,

EcoEngineers would like to thank the California Air Resources Board (referred to as CARB hereafter) for the opportunity to provide comments on the proposed Low Carbon Fuel Standard (LCFS hereafter) draft regulation. We are excited to be a part of the process and have prepared the following comments for your consideration.

Background & Qualifications
EcoEngineers is a renewable energy consultant and an EPA approved Q-RIN Quality Assurance Program (QAP) provider under the Renewable Fuel Standard (RFS). We conduct quarterly audits of over 70 domestic and international renewable fuel producers to ensure compliance under the RFS, and we have about 2.3 billion gallons of biofuel production enrolled in our compliance management programs.

EcoEngineers has extensive experience working with the California LCFS program and the CA GREET model. EcoEngineers has a full-time engineer dedicated to modeling fuel pathways in GREET and we have modeled more than 60 pathways using the CA-GREET model (1.8b & 2.0). We have submitted over 70 applications to CARB for registration under the LCFS. EcoEngineers has supported the development of biodiesel, renewable diesel, ethanol and biogas industries in California since the inception of the LCFS. We currently provide RIN QAP, compliance management, GREET modeling, and other consulting and auditing services to numerous clients who either produce biofuels in or sell biofuels into California and contribute to reaching the goals of the LCFS.

We believe CARB plays a leadership role in guiding global low-carbon fuel policies, and a successful LCFS program is key to reducing greenhouse gases from the transportation sector. We would like to congratulate CARB on steadfastly maintaining the policy objectives of the LCFS over the past decade and having the vision to take it into the next. Our comments are being provided with the intention of building on LCFS' past successes and helping CARB create a robust program for the future. B5-1

Conflict of Interest Provisions for a Verification Body (§ 95503)
EcoEngineers supports CARB's efforts to put in place a robust training program and clear qualification and conflict of interest standards for verification bodies and verifiers. B5-2 However, we disagree with CARB's approach of borrowing the standards for qualification, training and conflict of interest as-is from another program without thoroughly reviewing its applicability, utility and practicality for the LCFS. We believe there should be a review of specific components of the requirements for verification bodies and the conflict of interest provisions for their applicability to LCFS verification services. B5-3

CARB seems to believe that any verification body that also offers consulting service to the same client is at risk of being in high conflict. CARB seems to be partial to "pure play" verification bodies as the B5-4a

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preferred vehicle to conduct validation and certification work. CARB further seems to believe that the lure of selling consulting work will compromise a verification body's impartiality. We disagree with CARB's beliefs on this matter. CARB should not assume that a diversified company that offers consulting and auditing services is inherently pre-disposed to be biased or is at greater risk of being biased relative to companies that only offer verification services. A diversified company offering both verification and consulting services can perform quality, impartial validation, and, conversely, a company that only provides verification can be biased and/or tempted to compromise the quality of their validation. B5-4a cont.

EcoEngineers provides consulting and verification services to the biofuels industry. Our multiple business offerings and our broad client base mean that our future is not beholden to maintaining one client or one service. We are more likely to deny certification and lose a future stream of revenue than someone exclusively dependent on one service offering or a handful of clients. We urge CARB to take a broader view of this issue and allow greater flexibility for verification bodies to provide auditing and consulting services. Not doing so will also have the negative side effect of limiting the availability of experienced auditors, who may be working for a diversified company, to perform LCFS verification services.

We recommend that the conflict of interest provisions be limited to individual verifiers and verification teams, and not to verification bodies. We recommend CARB allow verification bodies to create isolated teams dedicated to performing verification for a specific client, and concurrently have separate consulting teams that offer consulting services to the same client. It will be up to the verification body to demonstrate, and for CARB to review and approve, how it intends to keep these teams' decision making independent of each other.

Below are some specific examples of how the conflict of interest requirements may be too restrictive:

§ 95503(b)(2)(A)

- This provision prohibits verification bodies from providing "data management system for data submitted pursuant to this subarticle or MRR." EcoEngineers offers a RIN tracking system to the biofuels industry that allows data transmittals from biofuel plants to the EPA for RIN generation purposes. The system acts as a virtual mail service that transfers data from one party to another and stores it for future retrieval for record-keeping and auditing purposes. We do not believe this creates a high conflict scenario and it provides our auditors up-to-date information on fuel transaction and credit generation at the facility. However, the broad language in the proposed regulation creates the potential for a high degree of conflict and may prevent us from using this valuable tool to enhance our verification services. B5-4b

§ 95503(b)(2)(H)

- This provision triggers a high conflict if a verification body provides "verification services that are not conducted in accordance with, or equivalent to, section 95503 requirements." The EPA's QAP program is currently the most common verification program among U.S. biofuel producers and it is unlikely to be in accordance with section 95503 requirements. We recommend that CARB modify the language in this section to allow current QAP providers to perform LCFS verification activities without triggering any conflict of interest. B5-4c

§ 95503(b)(2)(L) and §95503(b)(2)(C)

- § 95503(b)(2)(L) triggers a high conflict if a verification body provides "appraisal services of carbon or greenhouse gas liabilities or asset," and §95503(b)(2)(C) triggers a high conflict if a B5-4d

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verification body provides "consultative engineering" services. EcoEngineers sometimes provides its clients the current market value of renewable fuel credits as seen in 3rd party market transactions or other publicly available data such as CARB's website. This data may or may not be part of an independent economic analysis that compares potential revenues from credits with estimated capital and operating costs at a facility. It is our unbiased, independent opinion of the value of the credits that creates value for our clients. We do not believe these services trigger a high conflict, and there should be some allowance for these types of relationships to continue; however, the proposed rules create significant ambiguity and may prevent us from providing validation services for some clients. B5-4d cont.

Other General Comments

§ 95488.8(g)(1)(B) Specified Source Feedstocks

- EcoEngineers supports CARB's efforts to create more transparency in feedstock markets; however, we also caution against placing overly burdensome requirements on biofuel producers. The proposed record-keeping requirements for Specified Source Feedstocks require a fuel pathway holder that acquires Specified Source Feedstocks from 3rd party suppliers to maintain "information from material balance or energy balance systems that control and record the assignment of input characteristics to output quantities at relevant points along the feedstock supply chain between the point of origin and the fuel production facility." This may not be possible for biofuel producers who are not vertically integrated and who do not have the ability to force their suppliers to reveal this information. B5-5
- We recommend that CARB either allow the biofuel producer to maintain a letter of attestation from a 3rd party feedstock supplier or require access to directly audit the feedstock supplier. If CARB is going to directly audit the feedstock supplier, there should be more clarity on the roles and responsibilities of feedstock suppliers as Regulated Entities.

§ 95488. (c)(2)

- We request additional clarity on the transition to GREET 3.0. A timeline that demonstrates when a fuel pathway applicant can use GREET 2.0 versus 3.0 and CARB's review and approval plan for each will be useful. For example, will CA-GREET 2.0 pathway applications pending as of 1/1/2019 continue to be reviewed and certified into 2019, or will applications in the queue be rejected? B5-6

§ 95488.6. (b)(2)

- We support CARB's efforts to implement a robust verification program for fuel pathways. However, requiring that an initial validation be completed before an application can be reviewed and certified by CARB could delay the generation of credits.
- We recommend that CARB allow validation to be completed before or after the application has been reviewed and certified by CARB staff. LCFS credits generated post certification but prior to validation can be locked and held in the pathway holder's LRT account if quarterly reporting must be completed during the validation. This will allow applicants to begin fuel sales into California sooner and prevent potential delays that can be caused by 3rd party validators. B5-7

§ 95488.9. (b)(4)

- EcoEngineers supports CARB's efforts to offer fuel pathway applicants a temporary fuel pathway carbon intensity value that the can use for reporting purposes. However, we request the following additional clarifications on the temporary pathway application process: B5-9 B5-10

- What is the application process and method of submission to CARB staff? What data is required?
- Will CA-GREET 3.0 modelling be required for temporary pathway applications?
- Will an approved temporary pathway be posted on the CARB website and made available to any applicant meeting same process requirements, or will it be exclusive to the company or facility that applied? B5-10 cont.

§ 95486 Table 4

- In Table 4, "Energy Densities and Conversion Factors for LCFS Fuels and Blendstocks," the unit for the energy density of CNG is currently represented as MJ/Therm, both of which are energy units. Table 4 provides the default value for the amount of energy in a unit mass or unit volume for all other fuels, and it may be clearer if CNG followed the same logic. B5-11

Equal value for all verified credits

We believe it is important to provide a program that creates a level playing field for market participants. A verified LCFS credit should have equal value regardless of its originating facility. This can only happen if CARB offers a guarantee of authenticity for all verified LCFS credits. LCFS credits function as the currency for trading emissions reductions, and there cannot be any doubt in the marketplace of the validity of the currency. CARB, being the regulatory body issuing the currency, should stand behind it as a guarantor. The mandatory verification program developed, implemented and monitored by CARB should provide CARB the confidence to guarantee the validity of the credits.

B5-12

The absence of such a guarantee will lead to buyers of credits giving preferential treatment to established counterparties with larger balance sheets to mitigate any potential invalidity in the credit generation or verification process or it will lead to buyers implementing their own verification systems over and above the mandated one. Both of these consequences will defeat one of the main purposes of a mandated verification system: to create market confidence, liquidity, and a level playing field for all fuel pathways.

Downstream market participants should not have the responsibility of further authenticating a verified credit, and they should not suffer consequences of any verified credit they purchase being found invalid at a future date due to no fault of theirs. This does not mean that downstream buyers and regulated entities will have the license to practice reckless behavior and ignore obvious misrepresentations by suppliers. CARB should explore ways to balance a credit guarantee with other controls, so the market bears the cost of credit invalidation.

Demonstrating Compliance for RNG from Dairy Methane

EcoEngineers commends CARB on its vision to incentivize avoided methane emissions for RNG from dairy digesters, and we have seen a great deal of interest in the industry on this subject. B5-13 However, we would like greater clarity on the requirements for the fuel pathway. To the extent CARB can offer clear directions, we expect to see more projects coming online. Some of the common questions include: B5-14

- If the dairy has a spill event, will it impact the carbon intensity score?
- Do these projects need to be enrolled in the California cap-trade program in order to participate in LCFS? B5-15
- Projects in the cap and trade program are verified annually for the previous year and credits are issued subsequently. How does this match up against a quarterly LCFS reporting schedule? B5-16

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Upstream emissions for corn ethanol

EcoEngineers commends CARB on allowing low-carbon crude to participate in the LCFS program. We urge CARB to take a similar view for corn ethanol and allow practices that reduce GHG emissions from corn farming to reduce the CI of the ethanol produced from the corn starch. We recommend that CARB allow farming inputs to be calculated and provided for applicants that wish to determine the actual carbon intensity score for feedstock used at their facility. B5-17

Conclusion

We would like to thank CARB again for the opportunity to provide comments and applaud your efforts to implement the LCFS program. We look forward to working with staff to finalize the proposed regulation.

Please let us know if you have any questions about our comments.

Sincerely,

John Sens
Regulatory Consultant
jsens@ecoengineers.us
300 East Locust Street, Suite 313
Des Moines, IA 50309

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18-3-3
S. Mui

STi
Sonoma Technology, Inc.
Innovative Environmental Solutions

April 23, 2018

Simon Mui, Ph.D.
Senior Scientist and Director, California Vehicles and Fuels
Natural Resources Defense Council (NRDC)
111 Sutter St., 20th Floor
San Francisco, CA 94104

Re: Review of the California Air Resources Board (CARB) Document, *Appendix G, Draft Supplemental Disclosure Discussion of Oxides of Nitrogen Potentially Caused by the Low Carbon Fuel Standard Regulation*, released March 6, 2018

Dear Dr. Mui:

Thank you for giving me the opportunity to assist NRDC in its review of CARB documents related to the Low Carbon Fuel Standard regulation. This letter provides statements that highlight the findings of my review; it also includes descriptions of my background and Sonoma Technology, Inc. (STI).

Statements Regarding the Draft Appendix G CARB Document

In its March 6, 2018, draft disclosure discussion regarding oxides of nitrogen (NOx) potentially caused by the Low Carbon Fuel Standard (LCFS) regulation, CARB has likely over-predicted the NOx emissions potentially caused by the LCFS regulation. The following points illustrate why the NOx emissions estimates are likely over-predicted. Since CARB estimated the potential increased NOx emissions due to biodiesel use, the points presented here focus on biodiesel. The points presented here also focus on issues that relate to calendar years 2012, 2015, and 2016, since those are the years for which CARB estimated that the LCFS program resulted in past potential NOx emissions increases due to biodiesel use. Page citations refer to CARB's Appendix G March 6, 2018, document. B7-1

1. **CARB selected the one analysis method, from among the three methods it employed, that generated the highest estimate of potential NOx emissions due to the LCFS.** CARB used three methods to estimate potential NOx impacts, referring to them as Methods I, II, and III.
    a. Method I, a statistical analysis, evaluated California and U.S. biomass-based diesel fuel use, to discern whether the LCFS program had a statistically significant impact on biodiesel fuel use in California. CARB found, "Since the statistical models that staff attempted did not yield statistically significant results for biodiesel, staff could not find a correlation between biodiesel and LCFS credit prices through statistical modeling for the historical period [2009-2016]" (pp. G-1-2, G-1-7). In other words, Method I analyses did not find a significant impact on biodiesel use in California due to the LCFS.

1450 N. McDowell Blvd., Suite 200 • Petaluma, CA 94954 • 707.665.9900 • sonomatech.com

b. In Method II, CARB weighed oil prices, the federal Renewable Fuel Standard (RFS), the LCFS, and federal tax credits to apportion the fraction of financial incentives coming from federal compared to California policy to incentivize use of biodiesel. CARB found that, for the period 2011-2016, LCFS program incentives accounted for from zero to 31% of the overall incentives in place for biodiesel (p. G-18).

c. Under Method III, the approach that yielded the most conservative outcome, CARB added consideration of fuel transportation costs to its Method II approach. With Method III, CARB found that, for the period 2011-2016, LCFS program incentives accounted for from zero to 83% of the overall incentives in place for biodiesel (p. G-18). Staff used Method III as the basis for the NOx analysis, thereby picking the method that resulted in the highest assessment of LCFS-related NOx emissions from biodiesel use. CARB has acknowledged that its approach likely overestimated emissions: "...the estimates potentially overstate the impacts attributable to LCFS, and should be viewed as an upper-bound estimate of any potential impacts" (p. G-4). B7-1 cont.

2. **There could be a bias built into the Method III treatment of transportation cost that results in over-assigning causality to the LCFS.** Method III assesses whether the LCFS credit value is greater than fuel transportation cost; if it is, it assigns causality to the LCFS program for biodiesel produced and shipped to California. However, it is reasonable to assume that if fuel transportation costs to other destinations were higher than to California, then there would be a preference to ship product to California, all else held equal. Comparative data on transportation costs to destinations outside California were not included in the CARB discussion document. If the agency included such a comparison, it could show Method III may over-assign causality to the LCFS program.

In summary, CARB examined how much California biodiesel use can be attributed to the LCFS program. Using three analysis methods, CARB found varying results, but chose the analysis method (Method III) that maximized estimated potential NOx emissions resulting from biodiesel use due to the LCFS. In addition, the analysis method selected (Method III) may itself include bias that may overestimate the fraction of California biodiesel use attributed to the LCFS. These points suggest that the NOx emissions estimated by CARB as being associated with biodiesel use in California, specifically resulting from the LCFS program, are overestimated for 2012, 2015, and 2016, past years for which CARB estimated the LCFS program resulted in potential NOx emissions increases due to biodiesel use.

Qualifications and Background

1. I have over 30 years of professional air quality-related experience, including serving for four years as the Mobile Sources Section Chief for the U.S. Environmental Protection Agency, Region 9; for approximately 12 years as the Program Manager for the U.C. Davis-Caltrans Air Quality Project, and for over 22 years at STI, an air quality research firm. I have also taught transportation-related air quality issues for many years as an Adjunct Associate Professor at the University of Hawaii, and I have taught transportation policy and planning at U.C. Davis.

2. My areas of expertise include (a) transportation-related air quality issues, including on- and off-road vehicle activity, emissions, and related impacts on air quality; (b) near-road air pollution issues; (c) vehicle inspection and maintenance; and (d) research program oversight.
3. I currently serve as Vice President and Chief Scientist for Transportation Policy and Planning at STI. In addition, under the Transportation Research Board (TRB) of the U.S. National Academies of Sciences, Engineering, and Medicine, I currently serve as the Chair of the TRB Air Quality Committee.
4. I have a Ph.D. in environmental policy analysis from the University of Wales, a Masters degree in Public Policy from Harvard University's John F. Kennedy School of Government, and a Bachelors degree from Cornell University.

About STI

STI staff have been contributing continuously to the science and understanding of air pollution for more than 35 years. Founded in 1982, STI is an employee-owned firm of about 60 scientists, engineers, and support staff providing air quality and meteorological research and services. Our headquarters is in Petaluma, California; however, we also have field study and data analysis staff located in southern California. Our transportation-related air quality work includes a range of federal, state, and local support. Examples include providing TRB Air Quality Committee leadership team support under the U.S. National Academies, running the research program for an eight-agency transportation pooled fund on near-road air quality, and routinely providing training classes to help analysts complete transportation-related particulate matter (PM), carbon monoxide (CO), and mobile source air toxics (MSATs) analyses to address the National Environmental Policy Act (NEPA), California Environmental Quality Act (CEQA), and transportation conformity. STI scientists have experience with PM, CO, MSAT, and greenhouse gas (GHG) emissions and air quality modeling assessments; health impacts analysis support; on-road vehicle and construction emissions assessments; mitigation; GIS-based spatial analyses; the development and updating of analysis tools and guidance manuals; smart growth and transportation control measure analysis; strategic planning; interagency consultation; and onsite training and education.

Sincerely,

Douglas Eisinger, Ph.D.
Vice President and Chief Scientist
Transportation Policy and Planning

B_UCLA1_B8

18-3-3
Sean Hecht

To the Clerk of the Board, California Air Resources Board:

Attached is a revised version of our Comment on Proposed Amendments to the Low Carbon Fuel Standard, incorporating some non-substantive changes to the comments previously filed. Please refer to this version, which supersedes the version filed and docketed on April 23, 2018.

Ted Parson and Sean Hecht, Emmett Institute on Climate Change and the Environment, UCLA School of Law

Comment on Proposed Amendments to the Low Carbon Fuel Standard

Emmett Institute on Climate Change and the Environment, UCLA School of Law

April 23, 2018 – revised April 26, 2018

On behalf of the Emmett Institute on Climate Change and the Environment at the UCLA School of Law, we submit the following comments on proposed 2018 revisions to the Low Carbon Fuel Standard. These comments are based on a forthcoming Emmett Institute study on the LCFS, "Controlling Greenhouse Gas Emissions from Transport Fuels: the performance and prospects of California's Low Carbon Fuel Standard," by Edward A. Parson, Julia Forgie, Jesse Lueders, and Sean Hecht. The study reviews the history, design and performance of the LCFS, summarizes and evaluates the major policy critiques that have been levelled against it, and discusses four major points of policy design that will pose continuing challenges for managing and implementing the LCFS under evolving fuel market conditions and tighter carbon intensity targets after 2020.

Major policy critiques of the LCFS and their limitations:

The LCFS is a major pillar of California's climate policies, which has survived its early legal challenges, been strengthened, and generated large expansions of alternative fuel supply and significant reductions in overall carbon intensity in California's fuel markets.

The LCFS incorporates several large-scale design elements that contribute to its survival and effectiveness in advancing its central goal of promoting long-term reductions in transport fuel emissions. By separately targeting transport fuels, it enables marginal incentives strong enough to induce the required investments in exploratory, low-carbon alternatives. By controlling the complete fuel life cycle, it avoids fuel switching based on partial benefits that might be offset elsewhere in the life cycle. By its structure as an intensity standard, it requires technical improvements that do not vary with the activity level—i.e., that do not tighten when transport expands and weaken when it contracts. By maintaining internal budget neutrality between the costs and subsidies it distributes among fuels, it reduces consumer price impact and remains separate from larger-scale political and economic risks associated with the general state budget. And by using a market-based approach based on tradable credits within this structure, it brings the general advantages of market-based policies—flexibility, cost minimization relative to the specified policy goal, and incentives for innovation—into the context of a sectoral rather than an economy-wide policy. Its innovativeness and ambition have attracted widespread interest, and it increasingly serves as a model for policies elsewhere.

Yet the LCFS remains controversial. In addition to several legal challenges (on which it has largely prevailed, suffering only procedural burdens and a few years implementation delay), the policy has attracted various policy critiques that assert it is fundamentally wrong-headed.

Policy critiques have mainly targeted either the LCFS's ambition or its design. Those based on ambition are familiar from many other environmental issues and policies. They claim the targeted reductions are infeasible or excessively costly because the required quantities of low-CI fuel cannot be available in time, even in response to the strong incentives the policy will create. These criticisms are weakened by the history of similar claims advanced since the policy's inception, all refuted thus far by the progress achieved. Moreover, multiple plausible compliance scenarios have been identified to reach the proposed tighter 2030 target, and the credit clearance will ease short-term compliance if these prove too optimistic. None of these counter-arguments proves there cannot be a sharp increase in difficulty and cost under tighter targets post-2020, of course. But should this occur, ARB has the tools and record of making small adjustments as needed to manage this risk, while also keeping strong incentives in place.

The critiques based on LCFS policy design are more variable in details and in sophistication, but all are based in one way or another on the policy's focus being too narrow. In early years, the form of narrowness most criticized was that the policy was enacted by California, rather than nationwide or internationally.[1] Greenhouse-gas policies at larger jurisdictional levels are preferred, because cuts in smaller jurisdictions (even as large as California) can have only small effect on global emissions, and are vulnerable to "emissions leakage" – partly offsetting increases elsewhere, induced through world fuel or product markets. This is correct in principle, but not persuasive as a basis to reject California-level policies. Empirical estimates of leakage vary widely across sectors, and can be reduced by details of policy design.[2] And although the critique is typically employed to argue that smaller jurisdictions should simply wait for action at larger scale, it is silent on what to do if effective action at the preferred larger jurisdictional scale is not available – i.e., if the choice is between California action impaired to some degree by leakage, and no action.

More recently, as the LCFS has survived early legal challenges and been strengthened, its critics have shifted to charging that it is inefficient – inferior in its balance of environmental benefits and costs – because it is targeted too narrowly within California. Either it is too narrow in targeting the transport sector, and is thus more costly than policies that seek the cheapest cuts economy-wide via a broad emissions price.[3] Or it is too narrow in targeting fuel life-cycle emissions within the transport sector, and is thus more costly than policies that seek the cheapest cuts sector-wide via some form of emissions-based fuel tax.[4] There are two closely related causes for this claimed inefficiency within the transport sector, one again concerned with scope, the other with policy form. In its scope, the LCFS targets one of three points to influence transport emissions: the emissions intensity of fuel, not the energy efficiency of vehicles or transport activity levels. If there are cheaper reduction opportunities at these other decision points, the LFCS does not achieve minimum-cost reductions even within the transport sector. In its form, the LCFS is designed as an intensity standard. It controls an average quantity for each

1 See, e.g., L.H. Goulder, R.N.Stavins, "Challenges from state-federal interactions in US climate change policy", *Am. Econ Rvw.* 101:3 (May 2011), 253-257; J. Bushnell, C. Peterman, C. Wolfram, "Local Solutions to Global Problems: Climate Change Policies and Regulatory Jurisdiction," *Rvw. Envt. Econ & Pol.* 2:2 (Summer 2008), 175-193; M.L. Fowlie, "Incomplete Environmental Regulation, Imperfect Competition, and Emissions Leakage." *Am. Econ. Jrnl: Economic Policy* 1:2 (2009), 72-112.

2 Meredith Fowlie, Mar Reguant, Stephen P. Ryan, Measuring Leakage Risk. Report for ARB, May 2016, *available at* https://www.arb.ca.gov/cc/capandtrade/meetings/20160518/ucb-intl-leakage.pdf

3 See, e.g., C.R. Knittel, "Markets point to leaning more on cap-and-trade", Sacramento Bee op-ed, Jan 31, 2017.

4 Critics do not always explicitly state their preferred policy, but the best alternative for their case would be a fuel tax levied on fuels' life-cycle emissions content: this would require doing the same LC analysis for each fuel as done under the LCFS, but would then apply a uniform tax per embedded unit of LC emissions to all fuel delivered, rather than an average intensity constraint at the point of fuel import or distribution.

fuel producer rather than total or marginal emissions, equivalent to a combined tax on high-CI fuels (above the standard) and subsidy on low-CI fuels. Because the subsidy component increases production of low-CI fuels, the policy cannot achieve a given reduction at minimum cost. Moreover, as with any intensity standard, if low-CI fuel markets are highly responsive to the subsidy it is theoretically possible for the standard to increase total current-period emissions.[5]

These critiques have figured prominently in regulatory debates, and have been widely and uncritically repeated as allegedly showing the policy to be wasteful, ineffective, or otherwise wrong-headed. But the critiques do not succeed at making this case, for several reasons. First, the policy's claimed inferiority depends strongly on details of the modeling formulation. Even within the static, comparative-cost framework employed by the most sophisticated critics, the LCFS's inefficiency can be readily reversed under various plausible alternative formulations: for example, in a macroeconomic framework that considers the excess burden of input taxes;[6] in the presence of market power or incomplete emissions control across jurisdictions;[7] or if economy-wide emissions prices are held below their socially optimal level by political constraints.[8]

There are also two more basic weaknesses of these critiques that make their rejection of the LCFS unpersuasive, one concerned with the economics of policy design and one with the political economy of regulation. First, they all depend, informally or through formal modeling, on a static comparative-cost framework that presumes the goal of the LCFS is, or should be, to cut emissions either in the current period, or in a timeless world with no dynamics. Within this framing, the critiques are correct: current-period reductions under the LCFS cost more than an equal quantity of reductions chosen for minimum current-period cost over all decision points in the transport sector, or over the whole economy. But the critiques mistake the goal of the LCFS, which is to promote larger, longer-term reductions. Moreover, their comparative-static analytic framework cannot represent the distinct technical and market conditions that motivated development of the LCFS: multiple potential technological pathways, all subject to large uncertainties, long development times, and strong network and system effects. To the extent transport fuel reductions are needed to achieve deep overall emissions cuts, and these conditions impair the response of transport fuels to broad incremental policies, then critiques that ignore these conditions – and their conclusions that the LCFS is inferior to broader policies – are irrelevant to evaluating the policy in view of its actual goals and the conditions in which it operates.

Second, the broader policies critics identify as preferable to the LCFS face severe political obstacles that have thus far prevented them from being enacted, in effective form and at

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5 See, e.g., G.E. Helfand (1991), "Standards vs. standards: the effects of different pollution restrictions" *Amer. Econ Rvw* 81:3(622-634); see also S.P. Holland (2012), "Taxes and trading versus intensity standards: second-best environmental policies with incomplete regulation (leakage) or Market Power" *Jrnl of Envt Econ and Mgt* 63:3(375-387); D Lemoine, "Escape from Third-Best: Rating Emissions for Intensity Standards", *Envt and Res Econ* (24 February 2016). No empirical example of this perverse effect has ever been identified, and it is difficult to demonstrate even in quantitative simulations. For example, the simulations of Holland et al (Tables 2 and 2, pp. 133-134) demonstrate the opposite effect: various LCFS targets, while highly costly in their analysis, reduce total emissions by ***more*** than the required fractional reduction in fuel CI.

6 L.H. Goulder, M.A.C.Hafstead, and R.C.Williams, "General equilibrium impacts of a clean energy standard", *Amer Econ Jrnl: Econ Policy* 8:2, at 186-218 (2016).

7 S.P. Holland 2012, supra note 5.

8 J.D.Jenkins and V.J.Karplus, "Carbon pricing under binding political constraints," UNU-WIDER Working Paper 44/2016, April 2016.

the required level, in any jurisdiction. The allegedly superior policies would impose a uniform emissions price, either economy-wide or across the transport sector. To assess the plausibility of such policies as alternatives to the LCFS, it is instructive to consider how high a broad emissions price would have to be to achieve the LCFS's targets. The most prominent academic criticism of the LCFS provides estimates of that price level in its quantitative simulations: to achieve the LCFS's original 2020 target of a 10 percent CI reduction, the required emissions price ranges from about $1,000 to $12,000 per ton CO_2, corresponding to a fuel price increase of 60 cents to $12.50 per US gallon, under different assumptions about ease of substitution in the economy.[9] If you reject that target – either because you reject a separate fuel CI target, or because a 10 percent is too large – using economy-wide emissions prices even to achieve weaker, widely accepted near-term reduction goals has thus far been politically unachievable. No jurisdiction has enacted a broad emissions policy strong enough to match recent estimates of social damage of emissions, despite arguments for the theoretical superiority of such policies being well known for forty years. All such policies in force are either impaired by broad exemptions, or held far below estimates of socially optimal levels.[10]

Unlike these hypothetically superior but nowhere-enacted emissions policies, the LCFS is in force, at a level that is deploying strong incentives to reduce fuel-related emissions. It is likely that the same design elements that are major targets of criticism, notably its internal budget neutrality, have contributed to its enactment and survival. In addition to considering the conditions that motivated the enactment of the LCFS, criticisms of the policy would also be more persuasive if they considered these evident, long-standing constraints on feasible alternative policies. Otherwise, even if their technical claims are stronger than we argue they are, these wholesale attacks on the LCFS are effectively equivalent to advocating continued inaction on transport-sector greenhouse-gas emissions.

Yet even rejecting these wholesale attacks on the policy, the LCFS still faces significant challenges of policy design to effectively pursue its goal of promoting large long-term reductions in fuel CI. Taking the major structural elements of the LCFS as given – focusing on transport fuels, controlling life-cycle emissions via an intensity standard, and providing flexibility via tradable credits – four major points of policy design will pose continuing challenges for managing and implementing the LCFS: fuel and technology neutrality; the scope of the policy; the trajectory of reduction targets over time; and managing the LCFS's interactions with closely related policies.

Neutrality

The LCFS is intended to be neutral over the fuels and technologies it covers, imposing benefits or burdens only in proportion to each fuel's calculated life-cycle emissions. The mix of

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9 Holland 2012, Tables 2 and 3, pp. 133-134. The quoted values are the shadow value of an additional ton of emissions under the specified LCFS constraint.

10 The most recent "Social Cost of Carbon" exercise estimated marginal damage from 2015 emissions (model average at 3% discount rate) as $36/tCO_2$ (Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised August 2016), *available at* https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon-technical-documentation_.html. By contrast, a recent survey of emissions policies worldwide found that only four jurisdictions (Sweden, Switzerland, Finland, and Norway) had policies with nominal emissions prices above $31/tCO2e, all impaired by large exemptions. (World Bank Group, Carbon Pricing Watch 2016, *available at* https://openknowledge.worldbank.org/handle/10986/24288).

fuels supplied under the overall CI target is then driven by market decisions, as suppliers balance CI reduction, cost, and other factors. Although the great variability of factors and conditions that determine each fuels' calculated CI make neutrality a challenging aim to achieve in practice, ARB has done a good job realizing neutrality and addressing significant departures. The only explicit departure from neutrality in the LCFS is that petroleum-based fuels are regulated collectively rather than individually: while alternative fuels have individualized CI calculations, gasoline and diesel are assigned statewide average CIs, subject to periodic updating.

Neutrality is a useful design principle for the current state of knowledge on reducing fuel emissions: confidence that large CI reductions will be required, but substantial uncertainty over the relative prospects and benefits of various alternatives to realize these reductions. Given this state of knowledge, a fuel-neutral policy like the LCFS can advance two linked near-term objectives: providing incentives to develop a broad range of low-CI alternative fuels; and promoting learning and eliciting information about the prospects of various alternatives, without pre-judging which will be preferred. Over time, as knowledge advances about the likely or preferred fuel mix for the future low-carbon transport system, the value of a neutral policy will decline. As knowledge about the preferred endpoint emerges, policies should shift away from neutral promotion of a broad set of alternatives, toward managing the transition to the preferred endpoint effectively and efficiently.

Scope

Defining policy scope is fundamental to managing a separate policy for transport fuels. The LCFS's nominal scope is all fuels used for road transport in California, but it also includes a few low-CI off-road fuels. As a separate policy imposing higher marginal costs on transport fuel emissions than others, the LCFS must define a coherent boundary, and defend the boundary from attempts at arbitrage to exploit the large marginal-cost disparity. ARB has succeeded in managing the LCFS's scope so far, although some of its scope decisions appear mainly to have addressed concerns about short-term credit shortage by adding more low-CI, credit-generating fuels, such as electricity used in forklifts and some rail systems, and current proposals to include renewable jet fuel and low-CI alternative fuels used in off-road military vehicles. In the future, the credit clearance mechanism will ease this concern, while tighter targets and sustained higher credit prices will make other boundary-drawing challenges more prominent. High credit prices will strengthen incentives both for alternative fuel development, and for other activities less aligned with the policy's goals, such as developing technologies and systems that blur or dissolve the boundary, as well as fuel shuffling and related forms of emissions leakage.

Future boundary-drawing challenges will be highly technology specific, as illustrated by electric drive and carbon capture and removal technologies. Electric drive has seen rapid growth in light-duty vehicles, to a lesser extent in heavy road transport, especially transit buses. It has the potential for continued strong expansion, particularly in light vehicles, but still faces enough continuing barriers related to cost, performance, consumer acceptability, and infrastructure, that it is not assured to be the preferred or successful low-carbon option, even for light vehicles. The prospects for electric drive are strong, but still uncertain: they clearly merit continued and expanded LCFS crediting, but do not call for re-focusing low-carbon fuels policy preferentially on electricity rather than continuing to promote a wide range of low-CI alternatives through the LCFS. B8-1

But the design and implementation challenges of promoting electric drive through the LCFS while maintaining neutrality are substantial. For light-duty vehicles, where technical prospects are strongest and growth is fastest, LCFS incentives are hard to target effectively. The present targeting of LCFS electric credits on EV purchase decisions is sensible, since these drive production growth and cost reductions, but LCFS incentives can target only some of the associated barriers and are relatively weak. For the subsequent factors determining emissions – how much EVs are driven, and the CI of charging electricity – the targeting of LCFS incentives is weak. After vehicle purchase, most residential charging is not separately metered so LCFS credits must rely on weak proxies for actual vehicle use, although these can be improved with better charging data, via separate meters or direct collection from vehicles. B8-2 The challenges of heavy transport are the reverse of those for light-duty vehicles. Technical challenges to electrification are greater, but separate charging improves the targeting of incentives from LCFS credits, while heavy commercial usage makes them more valuable. B8-3 Additional CI reductions for any electrified transport modes will also depend on the mix of electrical generating sources. As an end-use-oriented policy in the integrated electrical grid, the LCFS will have limited ability to influence these decisions. They will require other policies to promote continued electrical decarbonization and electric-transport interactions, such as role of vehicle charging in energy storage and load management. B8-4

Carbon capture and atmospheric removal technologies may offer large reductions in net emissions but also present scope and boundary challenges for the LCFS. Some carbon capture opportunities fit squarely within transport fuel production: capturing and sequestering existing emissions streams from fuel production or processing, and producing low-CI synthetic fuels using carbon removed from the atmosphere. But the larger potential contributions of carbon capture or removal lie outside transport fuel production as presently defined. Counting carbon removal elsewhere or in other processes as reducing the CI of a transport fuel would require drawing artificial system boundaries for the CI calculation, under which the carbon capture or removal function more like offsets than emissions reductions. The associated boundary-drawing challenges are not just theoretical matters of what cuts really count as being in transport fuel. They also affect high-stakes practical issues of potential harms or scale limits in total carbon removal, when billions of tons of annual removals are already widely assumed and using carbon removal to offset substantial continuing gross emissions from transport fuels would represent a further large increase.

These concerns highlight the importance of keeping careful control over the pace of expansion of LCFS crediting for technologies, like carbon capture and removal, that may have large potential and flat marginal costs, but that may be judged not to comprise complete solutions to reducing transport emissions. The treatment of CCS in the current proposed amendments, crediting removals on site with fuel production processes or atmospheric removals incorporated into fuel products, strikes an appropriate and prudent balance. Further expansion of crediting for carbon capture or removal may be judged warranted in the future, but must be carefully controlled and gradual. B8-5

Target trajectory

A key element of LCFS policy design is its CI target and how this is tightened or otherwise adjusted over time to provide strong, steady incentives for development and expansion of low-CI fuels. Thus far, target adjustments have mainly responded to legal challenges and concerns about short-term credit shortages, but these are likely to be less prominent B8-6 considerations in the future. The LCFS's basic market-based structure with credit banking, as well as the credit clearance mechanism, pass some responsibility for managing the time trajectory of fuel development to private market actors. But ARB still has the responsibility to set and periodically adjust the CI target trajectory, as it did when the policy was adopted and has now proposed through 2030. Such a pre-announced target schedule is necessary to signal the policy's ambition, create appropriate incentives, and provide context for market actors' decisions to use or bank credits. With such a target trajectory in place, the credit market then both mediates the incentives for low-CI fuel development and provides information about realized and anticipated progress. Sustained high credit prices both make the incentives stronger, and signal difficulty responding in the short term.

There will always be unavoidable uncertainty on future progress in low-CI alternatives, and thus on the trajectory of future credit prices. To deal with these, ARB needs the discretion to adjust previously announced target schedules in response to large departures from projected progress. Given this uncertainty, the most basic design decision regarding targets is how to set the advance schedule relative to current projections of future progress: should the initial target schedule be biased toward greater ambition, with accompanying risk that future relaxations will be needed; or toward less ambition, with increased risk that future tightening will be needed?

B8-6 cont.

This decision can be analyzed in terms of the relative cost of the two types of error. Starting too weak then tightening means missing available reduction opportunities; giving inadequate incentives, so weak initial projections may become self-fulfilling prophecies; and later imposing unanticipated lump-sum burdens on fuel distributors who have deficits. Starting too strong then loosening risks weakening the credibility of initial targets, and gives incentives to firms that expect to have deficits to resist and conceal progress in order to get targets weakened. These two concerns may have limited impact, in practice, however. Risks to credibility of targets may not be consequential because target relaxation would only occur under conditions of sustained tight credit markets, and so would impose only small losses from highly favorable positions on low-CI investors. And obstruction might not be a serious risk because the divergence of interests between firms marketing high and low-CI fuels suggests that those with the strongest interests in target relaxation would have little influence on the pace of low-CI development. On balance, the cost and disruption from setting initial target trajectories ambitiously then later making small relaxations if needed are likely to be less than those from setting initial targets too weak and later having to tighten them. For the proposed target trajectory through 2030, since several plausible scenarios have been identified to reach the proposed 20 percent reduction or more,[11] this reasoning suggests that ARB should consider an initial trajectory with somewhat stronger targets, reaching a few percent beyond 20 percent CI reduction by 2030.

If future relaxations are required, these can be implemented in a few different ways. One possible approach would be to modify the credit clearance mechanism to drop the five-year constraint on carrying forward deferred obligations. This would broaden the quantitative relaxation available at the $200 price, making the mechanism more closely resemble a true price

B8-9

[11] Initial Statement of Reasons, Chapters 5 and 8, *available at* https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf; See also C. Malins, "California's clean fuel future: assessing achievable fuel carbon intensity reductions by 2030," March 2018. *Available at* https://nextgenamerica.org/wp-content/uploads/2018/03/Cerulogy_Californias-clean-fuel-future_March2018-1.pdf

B8-8 cont.

cap, but this change would raise two concerns. First, by letting participants accumulate open-ended quantities of deferred obligations, it would increase risk of compliance failure, by bankruptcy or other means. A compromise approach to limit this risk would be for ARB to grant such relaxations only case-by-case, subject to participant-specific assessment of default risk. Second, relying on the credit clearance mechanism as the vehicle for future relaxation would make most sense if ARB remained confident that the $200 credit price is the appropriate maximum: high enough to motivate major investment in innovations, but not so high as to risk serious disruption of fuel markets. If this is not the case, or if ARB does not want to rely on the clearance mechanism for this purpose, future loosening can also be achieved either by small explicit relaxation of forward CI targets, or implicitly by incremental expansions of the policy's scope to bring in additional low-CI fuels and uses, as was done for electric forklifts and rail system and is proposed for alternative jet fuel. Limited expansions in credit eligibility for carbon capture and removal would be one way to achieve such small relaxation, subject to the caution above that such carbon removal crediting must be kept under careful quantitative control. Whatever method is considered, ARB must carefully resist too-easy or too-early relaxation, because sustained high credit prices will be necessary to generate the needed development and investment in low-CI alternatives. B8-9 cont.

Managing policy interactions

The LCFS operates, and will continue to operate, in the context of other related policies. Managing interactions with these will be a major continuing challenge for the LCFS, affecting many elements of design and implementation. Thus far, the LCFS's major interactions have been with the federal Renewable Fuel Standard (RFS) and California's greenhouse-gas cap-and-trade system. These will remain significant in the future, in addition to increasing interactions with LCFS-like policies in other jurisdictions. The RFS differs in scope and policy structure from the LCFS. It has generated a large supply of mostly conventional biofuels that eased LCFS compliance under early weak targets, but is not designed to provide incentives for incremental improvements in CI within fuel types. The RFS is likely to be less relevant as LCFS targets tighten, unless it is modified to provide more effective incentives for low-CI biofuels.

The LCFS has interacted strongly with California's cap-and-trade system since the cap was expanded in 2015 to include fossil-fuel combustion emissions. These fuels now fall under both the stronger requirements of the narrower LCFS and the weaker requirements of the broader cap-and-trade system. Under this double coverage, it is highly likely that the LCFS suppresses cap-and-trade allowance prices and thus impairs the ability of the cap-and-trade system to motivate reductions in other sectors. Given that this double coverage is in place, the interaction can also be weakened or eliminated by introducing a cap adjustment mechanism, which would reduce the cap to track estimated reductions in cap-covered emissions achieved by the LCFS. Given the likelihood of inelastic short-run allowance demand, such adjustment need not reduce allowance auction revenues, but estimating the detailed response would require quantitative modeling of specific adjustment mechanisms. B8-10

Continuing enactment of LCFS-like policies in other jurisdictions, as now in place and proposed in several jurisdictions, will bring two types of potential interaction: interactions through linkage of trading systems, and market effects via demand for low-CI fuels. LCFS credit markets can in principle be linked, following the existing model of expanding inter-jurisdictional linkage of cap-and-trade systems. Such linkages can make larger and more liquid credit markets, but would require careful attention to coordination of both administrative trading B8-11 mechanisms (to avoid double-counting), and policy stringency and design (to avoid arbitrage). Such linkages are not presently feasible, due to inconsistent design between the LCFS and other systems now in force and proposed. In particular, other current and proposed LCFS systems exclude indirect land-use change from calculated CI of biofuels, so those systems will generate significantly stronger incentives for production of those biofuels whose CI includes a large iLUC component.

The more immediate interactions will be through effects of increased demand on low-CI fuel markets. Additional LCFS policies, like tightening of California's CI targets, will strengthen incentives for production of low-CI fuels and bid up their prices if production cannot expand apace. The additional policies will also increase incentives for fuel shuffling, since the new jurisdictions will compete with California for both newly produced and shuffled fuels. But because shuffling is an artifact of CI variation among the initially existing fuel supply mix, shuffled fuels are in fixed supply and will decline in relative importance as demand for low-CI fuels expands. As expansion of LCFS-like policies squeezes out claimed reductions of little merit or future promise, it will also clarify how much of present reductions is coming from shuffling, or from low-CI fuels that are real but also in relatively fixed supply, such as fuels produced from waste oils. As these sources reach their limits, the supply profile of other low-CI fuel options will be revealed more clearly. This will represent an additional source of uncertainty in future credit markets, although the response mechanisms already discussed – the credit clearance mechanism plus ARB's discretion to make small target relaxations under conditions of sustained shortage – are likely to provide adequate ability to respond to these conditions, as they do to uncertainties generated solely within California's credit market. 8-11 cont.

FF_CAF2_FF2

June 25, 2018

Mr. Sam Wade
California Environmental Protection Agency
Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Comments Submission
X. Modification to In-Use requirements for Specific ADFs Subject to Stage 3A
Section 2293.6 of the ADF Regulation

Dear Mr. Wade,

Thank you for the opportunity to submit comments specific to the subject matter.

Bifurcation

Biodiesel will play a key role in helping California meet its LCFS targets. Biodiesel use is forecasted to significantly grow over the next five years. Biodiesel blends above the seasonal allowances up to B20, hereinafter referred to as "BXX+", will underpin a significant portion of California's carbon intensity reduction goals. With the introduction of the ADF in January, the market has been establishing its BXX+ footing.

BXX+ presently finds its way into the market in a number of different ways with two common themes as follows:

1. NOX Mitigant is splash blended into biodiesel
2. BXX+ is splash blended

FF2-0

One of the growth limiting factors around BXX+ is that in-line blending (diesel and/or biodiesel and NOX Mitigant), at any locations, is a rarity. CARB should consider this reality because bifurcation will only complicate what is already a difficult market to supply BXX+.

NOX Mitigated biodiesel is generally purchased by 3rd parties that blend with diesel and supply the BXX+ market. Imagine a bifurcated market wherein this same 3rd party must buy biodiesel to (1) blend with diesel to supply the on-road market and (2) NOX mitigated biodiesel to supply the off-road market. Compared to the on-road ADF, where the truck stops dominate the BXX+ marketplace from a volume perspective, the off-road ADF suppliers are much less in numbers. The on-road ADF is more developed then the off-road market. The off-road ADF is in its infancy stages and will take more market development work.

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Bifurcation will, at some point, introduce another BXX+ fuel – one with NOX Mitigant, one without. The off-road market will incur NOX Mitigant expenses while the on-road market will not. As a result, the wholesale market price for off-road diesel will likely be higher than on-road diesel.

Bifurcation will slow, or possibly impede, off-road ADF advancements; at some point an off-road BXX+ product may not be available for supply because of its separate supply chain requirements. Undoubtedly if bifurcation was to occur, the off-road BXX+ market will, at a minimum backslide, and less biodiesel will likely find its way into this market segment. FF2-0 cont.

Biodiesel represents one of the key opportunities for fossil fuel replacement. Given the amount of off-road diesel in California (~30-35% of diesel fuel consumed in California), a significant portion of the diesel market may be precluded from using biodiesel, from a practicality perspective, if a bifurcation concept was adopted. Off-road diesel vehicles emit >250 tons per day of NOX emissions as well as additional particulate matter. The off-road diesel market could become one of the highest criteria pollutant emitting fuels if access to renewable fuel options is made difficult. Citizens of California in areas of high off-road vehicle populations face potential increased exposure of criteria pollutants should off-road BXX+ ADF volumes be negatively impacted because of bifurcation.

- How will bifurcation help meet the LCFS's carbon intensity reduction goals? FF2-1
- Why is CARB considering bifurcation and how will any off-road ADF backsliding be prevented? FF2-2
- Will CARB add language to the ADF which would define transition steps that must occur between on-road sunset and off-road continuity, ensuring BXX+ blends can reach the off-road market and if not, a sunset could not occur? FF2-3
  - For example, blending infrastructure must be sufficient and in place to ensure that off-road BXX+ does not become a stranded fuel especially in high off-road use areas? (note: establishing such a step may in fact accelerate the advancement of overall biodiesel use).

Section 2293.6(a)(4)(A)

"The portion of VMT by on-road diesel vehicles in California represented by NTDEs will be determined using <u>the most current CARB mobile source emission inventory and related tools</u>." FF2-4

- Are the EmFac reports being abandoned for another "tool"? If so, why?
- Can CARB provide more specificity regarding the "most current CARB mobile source emission inventory and related tools"?
  - What is that "tool" today and could that tool change in the future?
- Can CARB provide the tool's historical perspective on VMT and NTDE's? FF2-5

CALIFORNIA FUELING

- What is CARB's best estimate for when the sunset provisions for on and off-road will occur? What is the underpinning behind these estimates. FF2-6
- Will CARB be providing regular VMT and NTDE updates regarding progress towards the on and off-road sunset provisions? FF2-7

A final comment about NOX Mitigation. Treat costs have been significantly reduced with the approval of more cost-effective NOX Mitigants. CARB estimated NOX Mitigant biodiesel treat costs would be $0.10/gal (Staff Report 10/23/13); those estimates proved conservative – treat costs are better than forecasted. LCFS credit values are more than supporting this incremental cost. FF2-8

We believe that all things considered, bifurcation is not prudent or in the best interest of the public at this time – the risk is more than the reward. There are just too many unknowns and the better decision would be to readdress bifurcation once more progress is made with the ADF. By abstaining from bifurcation, CARB can send a clear message to the marketplace that BXX+ infrastructure must be advanced prior to further bifurcation consideration. FF2-9

We sincerely appreciate the opportunity to comment on CARB's LCFS proposed amendments. As always, we look forward to working with CARB through the rulemaking process.

Sincerely,

Patrick J. McDuff
CEO

CALIFORNIA
FUELING

FF_NBBCABA3_FF4

California Advanced Biofuels Alliance
1415 L Street
Suite 460
Sacramento, CA 95814
(916) 743-8935 *phone*

National Biodiesel Board
605 Clark Avenue
PO Box 104898
Jefferson City, MO 65110
(800) 841-5849 *phone*

July 5, 2018

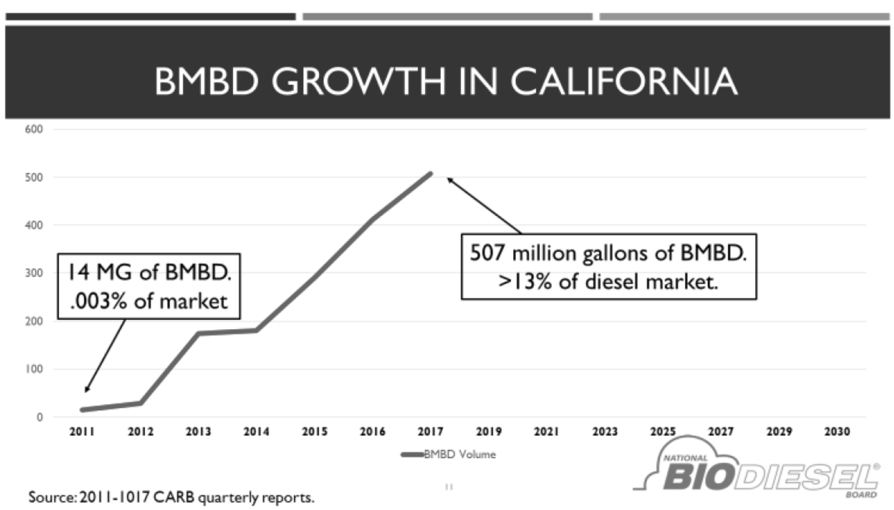
Clerk of the Board
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

Re: Proposed 15-Day Modifications to Low Carbon Fuel Standard Regulation.

Dear Air Resources Board Members and Staff:

Thank you for the opportunity to comment on this proposed regulation. The National Biodiesel Board (NBB) and the California Advanced Biofuels Alliance (CABA) continue to appreciate the tremendous job you and CARB staff do on behalf of the clean fuels industry and all Californians. It has been a pleasure to work with you over the years.

Biodiesel and renewable diesel continue to perform well under the low carbon fuel standard (LCFS). Biomass-based diesel volumes have increased from 14 million gallons in 2011 to 507 million gallons in 2017 and are expected to reach 1 billion gallons in 2020. Similarly, biodiesel and renewable diesel have transitioned from modest credit generators to mainstays of the program, accounting for 44% of LCFS credit generation in 2017. The chart below illustrates this progress.



On this and following pages, we have briefly detailed comments on selected portions of the regulatory package. Thank you for considering our views on these matters.

Alternative Diesel Fuel (ADF) Regulation

We are pleased to see the amendments regarding bifurcation of the on- and off-road diesel markets in the Alternative Diesel Fuel regulation. We believe these changes are in the best interest of the state's carbon reduction and public health goals. FF4-1

Co-Processed Renewable Diesel

We understand CARB's desire to facilitate the near-term ability of obligated parties to generate LCFS credits. However, due to the immense scale of refining operations and their astonishing level of complexity, we believe more time is needed to study this subject before carbon intensity pathways are issued. Specifically, we recommend that CARB restart its Co-processing Workgroup to help ensure pathways are promulgated in a manner that is 100% accurate for each refinery project and carried out in a manner fully consistent with the long-term goals of the LCFS program. We further believe that no pathways should be approved until the Co-processing Workgroup has reviewed key issues and developed a set of recommendations. FF4-2

We suggest the following areas for further consideration by CARB and/or the Co-processing Workgroup:

- Lifecycle models. CARB suggests that "Evaluating co-processing pathways using a Tier 2 framework is consistent with the goal of streamlining the pathway application and certification process."[1] At this point in time, we disagree that this is an appropriate approach because models for each respective refinery technology do not exist—they still need to be developed by CARB. And since the Tier 2 framework is usually masked in redacted statements, that process alone will not afford the level of public review necessary to provide confidence to stakeholders that carbon intensity values are accurate. FF4-3
- Public information. Refineries should be required to provide the same level of operational detail that has been made available by and for other industries. If co-processing is allowed to generate LCFS credits, the technology must go through a public process that provides sufficient information for the public to validate the accuracy of carbon intensity pathways. In addition, data marked as "confidential business information" submitted on Tier 2 applications should be reviewed by CARB legal staff to ensure it meets the criteria set forth under California law.
- Verification of renewable content. It is believed that a very small fraction of renewable feedstock inputs become renewable diesel fuel through co-processing. Therefore, it is critical that renewable content in finished fuel be measured via C14 radiocarbon dating

[1] https://www.arb.ca.gov/regact/2018/lcfs18/isor.pdf, page III-72.

rather than a mass-balance approach, which would overestimate renewable content. ASTM test method D6866 has been approved for this analysis.

- Limitation on co-processing. If co-processing is allowed under the LCFS, boundaries for this type of credit generation should be considered. We recommend the Refinery Investment Credit Pilot Program (RICPP) as a sensible model. Under RICPP, projects are of limited duration, refiners are not allowed to generate more than 20% of their obligation through the program, and credits cannot be traded. Given the incredible complexity and scope of refinery operations—and the corresponding potential for outsized errors—we believe moving forward in a methodical way is justified. FF4-3 cont.
- Additional processing. Carbon intensity pathways should account for energy used when (and if) refineries isomerize co-processed fuels to improve cold flow performance. FF4-8
- Emissions. We have not been able to find published literature regarding emissions and public health impacts for co-processed fuels. Since the technological process is the same as that which creates CARB diesel and the finished product is chemically indistinguishable from CARB diesel, we are not convinced that the environmental and public health impacts of co-processing should be assumed to be positive. FF4-9
- Technical properties. Potential concerns about cold-flow performance, stability, and incomplete refining could require additional test parameters and limits to be included. FF4-10
- Indirect effects. When bio-based feedstocks are comingled with fossil feedstocks, refiners should supply CARB with enough verifiable information to enable a full assessment of the indirect effects of co-processing on other refinery operations. This information should be made available in the same manner that Tier I framework biofuels have made information publicly available. FF4-11
- Alternative Diesel Fuel (ADF) regulation. Co-processed renewable diesel is a new fuel that should go through the ADF process like biodiesel has—and other renewable diesel replacement fuels will in the future. This step would ensure that emissions, public health, and operability data is available to CARB and the public for evaluation. FF4-12

<u>Comments on CARB Lifecycle Models</u>

CARB released revised versions of CA GREET 3.0 and the simplified Calculators for a 15-day comment period. The revised models address some of the comments provided earlier but have also introduced new issues. These comments address the latest versions of the models and focus on the biodiesel and renewable diesel pathways.

<u>CA GREET 3.0</u>

There are two aspects of the CA GREET 3.0 that have issues, the tallow rendering energy and FF4-13 continue to next page
the changes that CARB as made to the transportation energy use and resulting emission factors. FF4-14

3

Tallow Rendering Energy

The tallow rendering energy in GREET 2017 was significantly reduced as the pervious versions had misinterpreted the data in the peer reviewed paper that was used as the data source. The issue is discussed in the GREET memo which can be found here (https://greet.es.anl.gov/files/beef_tallow_update_2017). This is a simple correction of an error in GREET 2016 and it should be incorporated into CA GREET 3.0 and the BD/RD Simplified Calculator. It has a significant impact on the tallow pathways. FF4-13 continued from previous page

Transportation Emissions
There have been changes made to the transportation energy use for feedstocks and fuels after it was pointed out that in the previous version of CA GREET 3.0 a medium duty truck in the model was more efficient than a heavy-duty truck, which is not true. Unfortunately, CARB has made a number of other adjustments that have introduced new issues. FF4-14a

Rail
For the Rail energy use, CARB has added the same amount of energy as backhaul energy for rail movement. This is not necessary as the energy use for rail is calculated by taking the total fuel used for class 1 railroads and dividing that by the ton-miles of freight moved by those railways. This calculation automatically includes the energy used for back hauls and thus it is not necessary to double the value. However, even if it was not already included, it would not be the same value as the energy for a loaded car. There is really no justification given for adding the backhaul energy in Attachment C. FF4-14b

The ORNL Transportation Energy Data Book edition 36 reports (Table 9.8) that the total freight moved in 2015 was 1.744 million ton-miles and the energy used by the railroads was 516.4 trillion BTU for a total energy use of 294 BTU/ton-mile which would include the movement of empty cars. CA GREET 3.0 has 274 BTU/ton-mile for loaded and the same energy for unloaded movements. This is not correct and the back haul energy for rail should be removed from the model. The methodology is reported in section 6.2 of Appendix A.

Road
The road energy use in GREET is calculated by taking the vehicle fuel consumption and load and from that calculating the BTU/ton-mile. There is no equivalent data set as exists for the railways in which the total fuel used and the total freight moved is available, so the approach in GREET is reasonable. In this version of CA GREET, CARB has changed the load size and the fuel economy. As a result of these changes, the energy use for a HD truck for soybeans has been reduced from 3231 BTU/ton-mile to 1574 BTU/ton-mile and the energy use for the back haul is 79.3% of the loaded energy use. The US DOE report that a loaded class 8 truck typically weighs three times the unloaded vehicle weight (https://www.energy.gov/eere/vehicles/fact-621-may-3-2010-gross-vehicle-weight-vs-empty-vehicle-weight). The back haul energy use should be FF4-14c

closer to the ratio of the weight of unloaded vehicle to the fully loaded vehicle, that is 33%. There is no explanation for the new fuel economy values used by CARB.

While the energy use for the heavy-duty trucks decreased, the values for the medium duty trucks increased from 3088 BTU/ton-mile to 6231 BTU/ton-mile. The primary reason for this is that the load size was cut almost in half along with a reduction in the miles per gallon. No source for the data is provided and the back haul energy is the same 79.3% of the loaded energy, which is again too high a value. The DOE reports that the medium-sized trucks (truck classes 3-6) have payload capacity shares between 50% and 100% of the unloaded weight, which suggests that the back haul energy use should be 50 to 66% of the loaded energy use. FF4-14 c cont.

Barge

CARB has not changed the barge energy use in the latest version of CA GREET 3.0. We previously submitted comments regarding the fact that the barge energy use is higher than rail energy use and that this is not supported by the literature. Our previous comments are repeated here.

The rail and domestic water energy use in CA GREET is compared to the data from the Transportation Energy Data Book in the following table.

	CA GREET	Transportation Energy Use Data Book
	BTU/ton mile	
Rail	274	292
Barge	735	214

FF4-14d

In both cases the methodology is to take the total energy consumption for the mode and the total ton-miles of freight moved. This automatically accounts for the "back-haul" and there is no need to add additional energy for this movement as is done in CA GREET. It appears that the barge transport emission factor in CA GREET is too high by a factor of 3.4.

This is confirmed by the recent National Academies publication "Funding and Managing the U.S. Inland Waterways System: What Policy Makers Need to Know (2015)". In appendix G[2] where it is stated that:

> *Some studies show barge to be more energy efficient, while others show rail as the more energy-efficient mode. In terms of British thermal units per ton-mile, Davis et al. report that rail (294 Btu/ton-mile in 2012) is 40 percent more energy intensive than barge (210 Btu/ton-mile in 2012), nearly the same percentage difference as reported by Kruse et al. (2013).[1] These average energy intensity values represent the two-way transport average of upstream and downstream transport (upstream transport may require more energy to account for barge movement against downstream current velocities, and downstream*

[2] Appendix G. https://www.nap.edu/read/21763/chapter/15

transport energy may benefit from the river current). Alternatively, Dager (2013) reports even lower energy intensity for inland barge transport on the basis of independent data and fuel use modeling, corresponding to about 196 Btu/ton-mile, or about 60 percent better energy intensity than average rail. FF4-14d cont.

Biodiesel/Renewable Diesel Simplified Calculators

The BD/RD calculator has most of the previous errors removed, but there are still some issues that remain, which lead to incorrect results.

There are also some inconsistencies in how the same data is moved from the EF sheet to the calculation sheets. For example, on the Tallow tabs, cell G11 is zero and the calculator is pulling the standard value from the emission factors sheet, whereas other feedstocks move from the emission factor sheet to G11 and then into the calculations.

The most serious error is on the RD Production sheet in cell M158. This cell does not have an equivalent value on the previous version of the calculator. Zeroing it out in the current version gets the RD production emissions much more in line with the previous version. The previous version had those rows there but nothing in column M. The value in this cell should be removed as it is not clear what it is trying to calculate and clearly shouldn't be there.

On the canola sheet, the standard value for oil production (G11) is ~0.27 instead of the ~118 it should be. FF4-15

BD Production!J101 points to corn oil production, not UCO oil production. It should be changed to reference EF Tables!C44.

BD Production!J122 points to a tallow oil production value that is not equal to the one on RD Production. This is just more inconsistency where all oil production values really should be aiming at the same place. Setting it to equal to the formula used on RD Production J127 will bring the CI value for that stage in line.

On RD Production: M81:M84 use Fuel_Specs!$D$79 which is for soy oil, they should use Fuel_Specs!$D$81 instead. Similarly, on BD production M70:M85 uses the B79 instead of B81, Although these do not impact the results.

There is a discrepancy between BD and RD tallow is that BD tallow has an additional value for raw tallow transport, which is not included in the RD calculation.

The distance that feedstock is moved by heavy truck is hardcoded in most cases. For canola, it is moved 40 miles if being crushed for an oil that will become BD and 50 miles if being crushed for an oil that will become RD. They should be set to the same distance.

Conclusion

Thank you for considering our views. Our members have greatly enjoyed the opportunity to partner with CARB to help meet shared climate goals and we look forward to continuing this collaboration for years to come. If board members or staff have any questions, please feel free to contact us at any time.

Sincerely,

Jennifer Case
Chair
California Advanced Biofuels Alliance

Shelby Neal
Director of State Government Affairs
National Biodiesel Board

FF_FHR2_FF9

July 3, 2018

FLINT HILLS
resources

Submitted via Electronic Submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

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

Public Availability of Modified Text and Availability of Additional Documents and Information for Proposed Amendments to the Low Carbon Fuel Standard Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels

To the California Air Resources Board:

Flint Hills Resources (FHR) is pleased to submit comments to the modified text and availability of additional documents and information for the proposed amendments to the Low Carbon Fuel Standard (LCFS) and to the Regulation on Commercialization of Alternative Diesel Fuels (ADF).[1]

FHR operates fuel ethanol plants in Iowa, Nebraska, and Georgia as well as a biodiesel plant in Nebraska. We produce a large quantity of ethanol and biodiesel that may be sold within the state of California.

In summary, the proposed addition of **Section 95486.2 Generating and Calculating Credits for ZEV Fueling Infrastructure Pathway** would provide for a regulation that is a significant departure from the current program, whereby LCFS carbon credits issued to support the construction of ZEV fueling infrastructure would not represent actual greenhouse gas emission reductions. As currently constructed, the LCFS regulations provide for real and permanent greenhouse gas emissions reductions, when a transportation fuel with a carbon intensity lower than the annual average carbon intensity requirements is actually used. To be consistent with the current program, LCFS carbon credits should only be provided after low carbon fuels are physically supplied to ZEVs, thereby quantifiably reducing greenhouse gas emissions. In support of this overall comment, FHR provides the following detailed comments: FF9-1

The proposal to provide LCFS carbon credits for ZEV fueling infrastructure must be included within the Climate Change Scoping Plan and meet the requirements of Health and Safety Code Section 38561.

According to Section 38561(a), the California Air Resources Board (CARB) must prepare and approve a Scoping Plan for achieving the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from sources or categories of sources of greenhouse gases. California's 2017 Climate Change Scoping Plan does not include the proposal to provide LCFS carbon credits for ZEV fueling infrastructure, and therefore, must be updated. FF9-2

[1] For a variety of reasons, CARB's LCFS and Climate Change Scoping Plan are unlawful and FHR, by submitting these comments, is not suggesting that these actions are lawful.

– 4111 East 37th Street North – Wichita, Kansas 67220 – P.O. Box 2917 – Wichita, Kansas 67201-2917 –

Furthermore, LCFS carbon credits issued to support ZEV fueling infrastructure must meet the cost-effectiveness requirements within Section 38561(a) and (b). According to Section 38505(d), "cost-effective" or "cost-effectiveness" means the cost per unit of reduced emissions of greenhouse gases. By CARB staff's own admission during the June 11, 2018 workshop, these credits will not represent actual greenhouse gas emission reductions. As a result, any LCFS carbon credits issued by CARB and purchased at any cost by fuel reporting entities to retire carbon deficits for the purposes of compliance would not represent cost-effective greenhouse gas emission reductions. FF9-3

As part of Scoping Plan requirements within Section 38561(a), CARB is also required to consult with all state agencies to ensure that the greenhouse gas emissions reduction activities to be adopted and implemented are "complementary, nonduplicative, and can be implemented in an efficient and cost-effective manner". Additionally, in Section 38561(c) CARB must consider all relevant information pertaining to greenhouse gas emissions reduction programs in other states, localities, and nations. . However, the proposal does not consider if ZEV fueling infrastructure projects have or will also receive funding from other federal, state or local programs, such as the California Cap & Trade Program or from the California Public Utility Commission. As a result, infrastructure projects could receive multiple government subsidies, including the proceeds from LCFS carbon credit sales, that may exceed actual capital costs. FF9-4

By issuing carbon credits to support ZEV fueling infrastructure, CARB is creating a discriminatory preference for hydrogen and electricity over other low carbon fuels contrary to the equitable treatment requirements of Health and Safety Code Section 38562(b)(1). FF9-5

CARB has not issued or contemplated the issuance of LCFS carbon credits for other low carbon fuel production or infrastructure investments. With this proposal, CARB is also disregarding the significant capital investments (possibly stranding these assets) already undertaken by other low carbon fuel producers and will create a disincentive for future investments into the production and distribution of other low carbon fuels.

By adopting a regulation to issue LCFS carbon credits for ZEV fueling infrastructure, CARB will not meet the requirements of Health and Safety Code Section 38562(d)(1) that greenhouse gas emission reductions achieved are real and permanent.

Again, by CARB staff's own admission during the June 11, 2018 workshop, these carbon credits will not represent actual greenhouse gas emission reductions. In addition, these carbon credits are proposed to be provided for a period of 15 years for hydrogen refueling and 5 years for electric vehicle charging infrastructure, starting with the quarter following application approval and based upon refueling capacity and station uptime/availability. Although the Summary of the Proposed Modifications indicates that carbon credits will not be provided to stations that provide no throughput, a threshold throughput quantity is not established within the proposed regulations, and infrastructure investors could receive LCFS carbon credits only after dispensing nominal quantities of hydrogen or electricity. FF9-6

Greenhouse gases and other pollutant emissions during the construction of hydrogen fueling and electric vehicle charging stations should be included within the Environmental Assessment (EA) for this rulemaking, as required by the California Environmental Quality Act (CEQA). FF9-7

CEQA requires the disclosure of potential environmental impacts and identification of potential mitigation specific to the proposed LCFS regulatory amendments. Since this recent proposal was not comprehended within the draft EA included in the Staff Report, CARB should update the EA as required by 14 CCR Section 15088.5 of the CEQA Guidelines verifying that greenhouse gases and other pollutant emissions from the construction of 200 hydrogen refueling and 10,000 direct current fast electric vehicle charging stations will not cause a significant environmental impact. Otherwise, a decision not to recirculate the EA should be supported by substantial evidence in the administrative record per Section 15088.5(e). FF9-7 cont.

Should you have any questions, please contact FHR's VP, Quality and Compliance, Rita Hardy (rita.hardy@fhr.com, 316/828-7840), or myself, for further information or to schedule a meeting.

Sincerely,

Philip Guillemette

Philip Guillemette
Compliance Manager, Operations
Flint Hills Resources
philip.guillemette@fhr.com, 316/828-8440

FF_UNICA3_FF38

BRAZILIAN SUGARCANE INDUSTRY ASSOCIATION
ETHANOL • SUGAR • ELECTRICITY

July 5, 2018

Sam Wade
Branch Chief, Fuels Section
Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Modified Text and Availability of Additional Documents and Information for the Proposed Amendments to the Low Carbon Fuel Standard Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels

Dear Mr. Wade,

The Brazilian Sugarcane Industry Association ("UNICA") appreciates the opportunity to provide comments on the California Air Resources Board's proposed amendments to the LCFS, which was posted for comments on June 20th , 2018.

Brazil is the world's largest sugarcane producer and the second largest producer and exporter of ethanol with 22 percent of global production and 17% of exports in 2017.[1] Despite these volumes, sugarcane ethanol production uses only 0.6 percent of Brazil's territory[2] and reduces lifecycle greenhouse gas ("GHG") emissions by more than 100 percent[3] compared to conventional gasoline. Brazil's innovative use of ethanol in transportation and biomass for power cogeneration has made sugarcane a leading source of renewable energy in Brazil, representing 17.5 percent of the country's total energy supply, ahead of hydroelectricity.[4] Brazil replaced nearly one-third of its gasoline needs with sugarcane ethanol last year.[5]

UNICA is committed to helping CARB in meeting the goals of the LCFS by providing one of the lowest carbon intensive biofuels to be added to gasoline in use in California. Reducing dependence on GHG generating fossil fuels benefits the entire world, including the United States and Brazil. That is why UNICA works with CARB staff to continue supporting implementation of the LCFS, and why its members have provided volumes of low-GHG-producing sugarcane ethanol to help California meet LCFS goals.

[1] Percentages calculated by UNICA, based on LMC Ethanol Monthly Update (March 2018).
[2] Brazilian Institute of Geography and Statistics ().
[3] Seabra, J. E. A., Macedo, I. C., Chum, H. L., Faroni, C. E. and Sarto, C. A. (2011), Life cycle assessment of Brazilian sugarcane products: GHG emissions and energy use. Biofuels, Bioprod. Bioref., 5: 519–532. doi:10.1002/bbb.289
[4] National Energy Balance – Base Year 2016 (2017).
[5] *Id.*

We recognize the effort of staff to try to make the pathway registration process more efficient and less complicated. For this reason, we urge the Board and ARB staff to carefully consider the letter of suggestions[6] UNICA delivered at the last Board meeting on April 23rd. We believe we have included valuable and important suggestions that need to be implemented in order to help California better capture the reality of the domestic sugarcane ethanol industry and reap the benefits of this low carbon intensive biofuel, so we urge you to take them into consideration before finalizing any adoption of amendments.

FF38-1 continue to footnote below

In addition to the comments submitted on April 23rd, we would like to bring two main issues to the Board for careful consideration, these are both related to the amendments to the Tier 1 simplified CI calculator for sugarcane-derived ethanol:

1 - Maritime Transportation

Unfortunately CARB continues to insist on the notion of back-haul penalties for maritime transportation of sugarcane ethanol to California. It is unknown to us that CARB has obtained data to support its assertion that ocean tankers bringing ethanol fuel from Brazil to California will necessarily return to Brazil, and empty. From conversations with staff we understood that this back-haul emission penalty is due to a conservative approach staff wants to take in case this happens in the future. We decided to verify our observations that ethanol ships from Brazil do not return empty and would like to present our findings to staff in the Exhibit C of April 23, 2018 letter[7]

As the maps show, in the past two years nine ships have brought ethanol from Brazil to California, for a total of 10 trips (vessel High Valor has made the trip twice), from California these vessels called other ports to deliver other products. The tracking of these vessels confirmed our observations that ships do not necessarily go back to Brazil, and certainly not empty. Out of 10 trips, only one was back to Brazil, with the vessel carrying diesel. All other nine trips were to Asia, Europe and Mexico.

FF38-2 continue to footnote below

Maritime transportation would certainly not be efficient and affordable if vessels would travel empty around the world. Assuming that the energy consumption and associated emissions of the ocean tanker's round trip be attributed to sugarcane ethanol is highly speculative and arbitrary and causes a tremendous impact in sugarcane ethanol competitiveness in the California market. We urge staff <u>not to</u> consider the emission of shipments returning to Brazil, since it defers from current market and trading practices. Additionally, UNICA would like to request that staff specify what type of evidence CARB has obtained to justify such penalty on sugarcane ethanol.

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[6] UNICA's letter to CARB of April 23, 2018: https://bit.ly/2KJFEKO

FF38-1 continued from above

[7] UNICA's Letter to CARB of April 23, 2018, pages 23-32: https://bit.ly/2KJFEKO

FF38-2 continued from above

II- Mechanization

One input in the calculator that is of great importance to the Brazilian sugarcane sector is the mechanization input, given the advances and investments that the industry has made in this front in the last decade and the competitive advantages that set mills apart from their peers. We see that the version of the calculator posted online on June 20th does not allow for site-specific mechanization input and we urge staff to include this option before finalyzing the amendment adoption process.

According to the State-owned Brazilian Food Supply Company (CONAB in Portuguese), from the Ministry of Agriculture, Livestock and Food Supply (MAPA), the South-Central region, where the majority of UNICA members operate, has reached 95.6% of mechanization level in 2017/2018 crop year, compared to 28,5% one decade ago[8]. Indeed, this index is even higher according the Sugarcane Technology Center (CTC). Following its data, the mechanical harvesting in areas owned by mills, located in South Central region, reached 98% in the named season. FF38-3

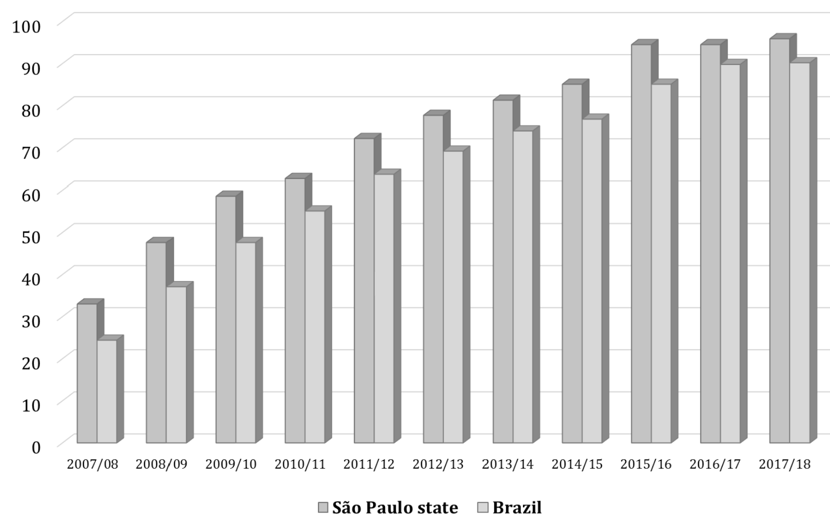
It is important to mention that this is the region responsible for all the ethanol exported from Brazil to countries such as the United States, Japan and the European Union.

As CARB is aware, São Paulo state government, in partnership with UNICA and sugarcane growers association (ORPLANA), created in 2007 a Green Ethanol Protocol, a pioneer initiative that, among other commitments, eliminated pre-harvest field burning in 2017. According to the Environmental Secretary, 95% of all sugarcane processed in the São Paulo state is under the management of certified parties.[9] Since June 2017 this commitment has entered into a new phase, now called More Green Ethanol Protocol, that continues to reiterate the pre-harvest field burning commitment, but includes the important commitment of restoring reparian vegetation around cane fields.

[8] http://www.conab.gov.br/OlalaCMS/uploads/arquivos/17_08_24_08_59_54_boletim_cana_portugues_-_2o_lev_-_17-18.pdf (page 60)

[9] Slide 3 of the document: http://arquivos.ambiente.sp.gov.br/etanolverde/2017/06/etanol-verde-relatorio-preliminar-safra-16_17-site.pdf

Sugarcane Harvesting– Fast Mechanization Process in Brazil



Source: CONAB (National Supply Company, from the Brazilian Ministry of Agriculture, Livestock and Food Supply

FF38-3 cont.

As previously mentioned, industry has invested a great deal in mechanization in the sector in the last decade. Investments that helped sector reach a level of 57% of GHG emissions reduction from harvesting over the past 10 years (from 4.8 to 2.1 g CO_2eq/MJ of ethanol), considering the parameters given in Table 1. We believe there is strong evidence that the soil carbon stocks increase due to unburned mechanized harvesting[10]. Estimations from Figueiredo and La Scala Jr (2011)[11] indicate that the emissions in the mechanized harvesting are almost 1500 kg CO_2eq ha^{-1} $year^{-1}$ lower than those for the burned harvesting, since it leads to a soil carbon sequestration of more than 1170 kg CO_2eq ha^{-1} $year^{-1}$.

Table 1: Parameters used for the estimation of emissions balance between burned and mechanized harvesting

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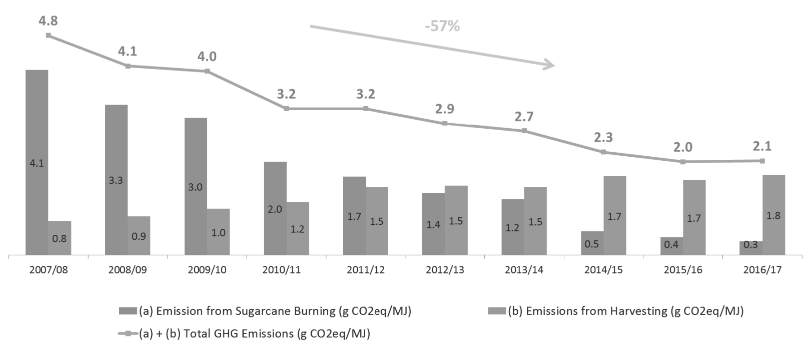
[10] Cerri, C. C., Galdos, M. V., Maia, S. M. F., Bernoux, M., Feigl, B. J., Powlson, D. and Cerri, C. E. P. European Journal of Soil Science; Special Issue: Soil Organic Matters; Volume 62, Issue 1, pages 23–28, February 2011
[11] Figueiredo EB, La Scala Jr N. Greenhouse gas balance due to the conversion of sugarcane areas from burned to green harvest in Brazil. Agriculture, Ecosystems and Environment 141 (2011): 77-85.

Parameter	**Value/source**
% Mechanized harvesting	CONAB
Sugarcane production	UNICA[12]
Sugar and ethanol production	UNICA[12]
Straw burning emissions	2.7 kg CH_4/t dry matter burnt[13]
	0.07 kg N_2O/t dry matter burnt[13]
Straw to cane stalk ratio	140 kg (dry basis) per tonne of stalk[14]
Harvester's diesel consumption	74 L/ha [15]
Life cycle diesel emissions	83.8 g CO_2eq/MJ [16]

FF38-3 cont.

Emissions Balance (Burning vs. Mechanization)



In the CI calculator for sugarcane ethanol, CARB proposes two default values for sugarcane mechanization for Brazil: 80% for São Paulo state and 65% for other states in the Center-South region. By choosing to use the default values, mills will not need to have this input verified. UNICA will probably have members who will be satisfied using the default value, however, the vast majority of our members located

12 http://www.unicadata.com.br/

13 IPCC 2006, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds). Published: IGES, Japan.

14 Hassuani SJ, Leal MRLV, Macedo IC. Biomass power generation: sugar cane bagasse and trash. Piracicaba: PNUD Brasil and Centro de Tecnologia Canavieira; 2005.

15 Adapted from Macedo IC, Seabra JEA, Silva JEAR. Green house gases emissions in the production and use of ethanol from sugarcane in Brazil: The 2005/2006 averages and a prediction for 2020. Biomass and Bioenergy 32 (2008): 582-595.

16 European Parliament and Council of the European Union, Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009, on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC, Official Journal of the European Union of 5 June (2009).

in Sao Paulo, who have nearly all of its sugarcane harvesting mechanized, and a considerable number of members in other states, prefer to prove that they are at highest level of mechanization, as abovementioned reported by CONAB and CTC.

For this effect, UNICA would like to request, once again, that CARB includes an option for self-declared mechanization percentage in the CI calculator, we are aware that mills opting for it will have its data and its mill audited by a CARB authorized third party verification body. In the April 23rd letter[17] to CARB, Exhibit A, UNICA has suggested an outline for proving mechanization levels in Brazil, we encourage staff analyze it and make a decision on the process in order to include the site-specific input as soon as possible. FF38-3 cont.

UNICA member mills, who represent the vast majority of Brazilian mills registered with CARB, are highly sophisticated enterprises who invest a great deal in the automatization of their agricultural and industrial processes. Third party verifying bodies in Brazil have, for years, audited mills' systems for certification schemes like the Bonsucro, EPA's RFS program and the LCFS in itself. We encourage CARB staff to continue to reach out to verification companies in Brazil, as well as to regulatory agencies in the country, in order to clarify doubts or misunderstanding regarding the automatized systems used by sugarcane mills. FF38-5

We believe providing these options are not only the best way to capture the reality of sugarcane mechanization practices in Brazil, but it is also the fairest approach to allow Brazilian ethanol to compete in the Californian market.

We commend CARB for its efforts to simplify and make the LCFS registration process more efficient. We want to make sure that the amendments proposed will indeed have these consequences and will allow for a closer-to-reality carbon intensity number for sugarcane ethanol. We would like to see more volumes of low carbon Brazilian sugarcane ethanol entering the Californian market. We urge CARB to consider our suggestions and ensure that sugarcane ethanol is fairly scored in the GREET-CA 3.0 modeling and that Californian consumers reap the benefits of sugarcane ethanol. We are at staff's disposal to work in any aspect of our suggested modifications, or to provide any additional data from the current experiences and anticipated trends in Brazil. FF38-6

Sincerely,

Leticia Phillips

Leticia Phillips

Representative-North America

---

[17] April 23, 2018 UNICA's letter to CARB, Exhibit A, page 12: https://bit.ly/2KJFEKO

FF_CRF2_FF42

CALGREN
Renewable Fuels

June 27, 2018

Sam Wade
Low Carbon Fuel Standard
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Comments on "Proposed Amendments to the Low Carbon Fuel Standard Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels"

Calgren Renewable Fuels appreciates the opportunity to comment on the proposed changes to the Low Carbon Fuel Standard regulations.

We would like to make the following recommendations and comments:

1. Modifications to Section 95483. Fuel Reporting Entities (1).

   Calgren Renewable Fuels would like to support the proposed extension of the transfer period for credit or deficit generator status. Our recommendation is to extend the period to four quarters. It is our belief the extension will provide additional support to obligated parties to accurately generate and transfer credit, especially credits generated by a dairy digester cluster. Dairy digesters are often operated at ambient temperatures, thus causing their output to be almost twice as great in the summer heat as opposed to the winter cold. Storage of biomethane may be required in order address this seasonality. Allowing four quarters of flexibility would match up well with the inherent seasonal swings and allow for this contemplated storage. FF42-1

2. Addition of Section 95486.2. Generating and Calculating Credits for ZEV Fueling Infrastructure Pathways.

   Calgren questions the wisdom of this proposed amendment. Allowing one or two types of renewable vehicle refueling facilities to generate credits based upon capacity while other types must report based upon carbon avoided creates a dangerous hierarchy; with all due credit to the Governor's office, they are attempting to pick winners and losers rather than letting science take its course. This goes directly against the ARB 2030 Climate Change Scoping Plan. The Scoping Plan calls for a "balanced mix of strategies" to provide California with "the greatest level of certainty in meeting the [climate] target at a low cost while also improving public health, investing in disadvantaged and low-income communities, protecting consumers, and supporting economic growth, jobs and energy FF42-2

11704 Road 120 • P.O. Box E • Pixley, CA 93256
Office Phone 559-757-3850 • Fax 559-757-3852

CALGREN
Renewable Fuels

diversity." The proposed amendment effectively has narrowed the range of acceptable fuel technologies. This change risks sending the message that the State will ignore CI reduction if it results from "disfavored biofuels". Yet many such "disfavored biofuels," such as ethanol and biodiesel produced in needy parts of the state, such as the Central Valley, support a clean energy economy. This provides more opportunities for all Californians, provides a more equitable future with good jobs and less pollution for all communities, and improves the health of all Californians by reducing air and water pollution. The Scoping Plan also calls to increase production of renewable gas to support the reduction of Short-Lived Climate Pollutants. With the state turning to an electric- and hydrogen-only policy, many of the benefits for renewable natural gas as vehicle fuel will be lost. FF42-2 cont.

We would like to warn ARB on the effect on the Low Carbon Fuel Standard program with the adoption of this change. The programs continued validity is in jeopardy with a policy that clearly shows that the ARB is no longer fuel neutral.

3. Modifications to Section 95487. Credit Transactions.

We appreciate ARB adding language to clarify in additional text in section 95487(a)(2)(B) does not prohibit the contracting for future delivery of LCFS credits. The ability to trade future credits will provide market stability to credit trading. FF42-3

4. Modifications to Section 95488.9. Special Circumstances for Fuel Pathway Applications.

a. We support the change in section 95488.9(b) to improve the temporary CI value of dairy biomethane to -150 gCO2e/MJ. Recognizing the outstanding CI reduction in dairy biomethane will help support this new industry in the state. FF42-4 However, a similar temporary CI value must be applied to other renewable fuels, as set forth in the comments below, not just to CNG/LNG. FF42-5

b. Biogas or biomethane can be used create a variety of biofuels. Calgren Renewable Fuels plans to use biomethane from a dairy digester cluster to produce ethanol and biodiesel. The new proposed definition of biomethane 95481(a)(19) states "Biomethane" is a biogas…"which has been upgraded for use in natural gas vehicles." The definition could be interpreted to state that biomethane can only be used to create CNG or LNG. It is our understanding that these fuels should be allowed to claim avoided methane benefits for any and all biofuel production. Various uses for biomethane will be used by Calgren as input to make low carbon fuels. FF42-6

11704 Road 120 • P.O. Box E • Pixley, CA 93256
Office Phone 559-757-3850 • Fax 559-757-3852

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5. Addition of 958488.3. Calculation of Fuel Pathway Carbon Intensities.

We applaud the work by ARB is the creation of the Tier 1 Simplified Calculators. As mention is preceding comments, we would like the ability to claim avoided dairy emissions for more than use in CNG and LNG. It is our thought that all of the simplified calculators include an "Avoided Emission" tab using the same manure methane emissions calculation as exist in the 95488.3 (b)(7) "Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure". FF42-7

6. As implied by our foregoing comments, we are eager to find an acceptable way to avoid being penalized for being the first dairy cluster project in California. Because of inherent delays in arranging for gas pipeline injection, the first 6-8 dairy digesters in the first dairy digester cluster in California are not likely to produce CNG/LNG vehicle fuel. Rather, they will initially supply their biogas/biomethane as an input to make low carbon ethanol and/or biodiesel at the Calgren Renewable Fuels facility near Pixley, and only later transition to CNG fueling. There are no other dairy digesters clusters anywhere in the state likely to produce CNG fuel in the next 12 month. Thus it is important to recognize that while converting dairy digester gas to CNG is a long-term goal, the near-term use of dairy digester gas in ethanol production and biodiesel production is an important first step.

a. One way to do this might be to rename the calculator listed in 95488.3(b) (7) to be "Simplified CI Calculator for Biomethane Compressed Natural Gas/Liquid Natural Gas from Anaerobic Digestion of Dairy and Swine Manure, since various other uses of biomethane can and will be employed. Any alternative that works is acceptable. FF42-8

b. Through our affiliate, Calgren Dairy Fuels, we have signed up fifteen dairies and are in advanced discussions with others. While the actual number of digesters built may be less (one dairy was sold and two other dairies will share a digester), the point is that new digesters will be serially added over an extended period of time. Likewise, CNG refueling stations will be added serially, with at least one new station contemplated to be built next door to our biogas upgrade facility. We appreciate that ARB will need at least ninety days of data for each of the new digesters. Finding an acceptable way to avoid losing the carbon credits during those data collection periods is important. We believe that preserving the maximum amount of regulator flexibility will be vitally important.

c. In addition to granting new dairy digesters a conservative temporary CI value of -150, we think ARB should be careful to preserve the concept that verification will only occur over twenty-four month periods and only compare claimed carbon savings to actual

11704 Road 120 • P.O. Box E • Pixley, CA 93256
Office Phone 559-757-3850 • Fax 559-757-3852

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carbon savings. As noted earlier, dairy clusters typically involve ambient digesters that are subject to substantial seasonal swings. This is often a detriment. However, with appropriate regulatory flexibility and verification over two whole seasons, dairy clusters may someday benefit by "smoothing out" high production periods and low production periods. FF42-8 cont.

Sincerely,

Tim Morillo

Tim Morillo
Plant Manager

11704 Road 120 • P.O. Box E • Pixley, CA 93256
Office Phone 559-757-3850 • Fax 559-757-3852

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growth energy™
America's Ethanol Supporters

701 8th Street, NW, Suite 450, Washington, D.C. 20001
PHONE 202.545.4000 FAX 202.545.4001
GrowthEnergy.org

July 5, 2018

By Electronic Mail
Clerk of the Board
California Air Resources Board
1001 I Street, 23rd Floor
Sacramento, California 95812

Re: Proposed Amendments to the June 20, 2018, Notice of Public Availability of Modified Text and Availability of Additional Documents and Information for the California Low Carbon Fuel Standard Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels

Dear Madam:

Growth Energy, an association of the nation's leading ethanol manufacturers and other companies who serve the nature's need for alternative fuels, is submitting to you the enclosed materials in response to proposed amendments to the June 20, 2018, Notice of Public Availability of Modified Text and Availability of Additional Documents and Information for the California Low-Carbon Fuel Standard Regulation and the Regulation on the Commercialization of Alternative Diesel Fuels. These materials also include environmental comments being submitted to the Air Resources Board and the Executive Officer pursuant to the California Environmental Quality Act and the Board's implementing regulations.

Growth Energy may file additional materials in one or both rulemaking files for consideration in connection with this agenda item at a later time, as permitted by the California Government Code and the Public Resources Code.

If there are logistical questions concerning these submittals, please contact Mr. John P. Kinsey of Wanger Jones Helsley PC at 559-233-4800.

Thank you for your consideration and assistance.

Sincerely

Chris Bliley
Vice President of Regulatory Affairs
Growth Energy

Page 1 of 1

STATE OF CALIFORNIA

AIR RESOURCES BOARD

PROPOSED AMENDMENTS TO THE LOW CARBON FUEL STANDARD REGULATION AND TO THE REGULATION ON COMMERCIALIZATION OF ALTERNATIVE DIESEL FUELS

GROWTH ENERGY'S RESPONSE
TO THE NOTICE OF PUBLIC AVAILABILITY OF MODIFIED TEXT AND
AVAILABILITY OF ADDITIONAL DOCUMENTS AND INFORMATION DATED JUNE 20, 2018

JULY 5, 2018

For further information contact:
Mr. Chris Bliley
Vice President of Regulatory Affairs
Growth Energy
CBliley@growthenergy.org
202-545-4000

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Comments of Growth Energy on the Proposed Amendments to the June 20, 2018, Notice of Public Availability of Modified Text and Availability of Additional Documents and Information for the Low Carbon Fuel Standard Regulation and to the Regulation on Commercialization of Alternative Diesel Fuels

Growth Energy respectfully submits these comments on the June 20, 2018, Notice of Public Availability of Modified Text and Availability of Additional Documents and Information (the "15-Day Notice") for the rulemaking on the proposed amendments to the low carbon fuel standard ("LCFS") regulation and the regulation on commercialization of alternative diesel fuels ("ADF"). Collectively, the proposed amendments to the LCFS and ADF regulations are referred to in these comments as the "Proposed Amendments," while the proposed modifications to the LCFS and the ADF regulations identified in the 15-Day Notice are referred to as the "Proposed Modifications." These comments are also accompanied by expert reports submitted by (i) Thomas Darlington of Air Improvement Resource Inc. and Donald O'Connor of (S&T)[2] Consultants Inc.; (ii) Jim Lyons of Trinity Consultants; and (iii) H-D Systems, which are enclosed as Exhibits "A" through "C."

Growth Energy has several concerns regarding the Proposed Modifications, and believes several changes could be made to enhance the regulation. For example, to ensure the Proposed Amendments are based on "the best available economic and scientific information" available to CARB, (Health & Saf. Code, § 38562, subd. (e)), Growth Energy recommends that CARB modify its calculation of the direct and indirect emissions of corn and cane ethanol, and use updated versions of CA GREET and GTAP. Similarly, CARB should revise the EERs for various electricity pathways to ensure they are supported by the evidence. FF56-1 FF56-2

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Growth Energy is also concerned that the Proposed Modifications seek to treat hydrogen and electricity differently than other lower CI alternative fuels, and strongly suggests that CARB take a different approach that would achieve real and quantifiable greenhouse gas emissions. As such, Part II, Section A of these comments explains that, to the extent CARB issues credits for electricity and hydrogen capacity, CARB should also provide credits for capacity generated for other lower CI alternative fuels. FF56-3 FF56-4

Part II, Section B of these comments explains why the Proposed Amendments and Proposed Modifications should receive additional input from the public. Specifically, since 2009, the LCFS has been based on a system under which regulated parties would receive credits based on carbon intensity ("CI") and actual reductions in greenhouse gas emissions. The Proposed Modifications depart from the longstanding function and intent of the LCFS regulation, and propose to provide credits for the development of hydrogen and electricity charging infrastructure and unused capacity; in order words, credits would no longer be tethered to direct reductions in emissions. CARB staff itself has acknowledged these modifications are "certainly a philosophical departure from what the program has been about in the past . . . ." (Exhibit "D.") In light of this significant change in both philosophy and function, a 15-day review process is insufficient under the Government Code. The Proposed Modifications are not "sufficiently related" to the original text, and therefore a 45-day review period is required under the California Administrative Procedure Act, Govt. Code, § 11350, *et seq.* (the "APA"). In addition, to comply with the California Environmental Quality Act, Pub. Resources Code, § 21000, *et seq.* ("CEQA"), the Environmental Assessment ("EA") should be revised and recirculated based both on the significant change in the nature of the "project," and the potentially significant environmental effects resulting from the implementation of the Proposed Modifications. FF56-5 FF56-6

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Part II, Section C urges CARB not to consider the Proposed Modifications on the basis that they would not "achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from those sources or categories of sources, in furtherance of achieving the statewide greenhouse gas emissions limit," as required under AB 32. (Health & Saf. Code, § 38560.5, subd. (c).) FF56-7

Part II, Section D explains that, unlike the Proposed Modifications, Growth Energy's E15 Alternative would result in actual reductions of greenhouse gas emissions; thus, CARB should fully evaluate the incorporation of E15 into the LCFS as an alternative. FF56-8 Part III, Section E, in turn, explains that the Standardized Regulatory Impact Assessment ("SRIA") prepared under Section 11346.3 of the Government Code should be revised to address the dilution of credits and credit values caused by the issuance of credits for unused capacity at hydrogen and DC fast charging stations. FF56-9

Part III, Section A of these comments explains that, pursuant to Section 57004(b) of the Health and Safety Code, CARB should undertake a peer review to evaluate the "scientific portions" of the Proposed Modifications. FF56-10 Part III, Section B explains that CARB should revise the LCFS and ADF to address comments previously raised by Growth Energy. FF56-11

I. The CI Values for Corn Ethanol, Cane Ethanol, and Electricity should be <u>Based on the Best Available Economic and Scientific Information</u>

AB 32 requires that, in adopting amendments to the LCFS regulation, CARB establish "the maximum technologically feasible and cost-effective" method of reducing greenhouse gas emissions. (Health & Saf. Code, § 38561, subd. (a).) CARB must also use "the best available economic and scientific information . . . ." (Health & Saf. Code, § 38562, subd. (e).) FF56-12

As an initial matter, Growth Energy asks that CARB define what it contends the term "best available scientific information" means. This is important so that a reviewing court can

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assess whether CARB is reasonably construing the term for purposes of its development of the Proposed Amendments. This is of particular concern here because CARB appears to be relying on little scientific information in its efforts to provide credits for unused infrastructure, while at the same time declining to give adequate consideration to new data and findings concerning the direct emissions of various fuels and indirect land use change impacts. FF56-12 cont.

Under any interpretation, the Proposed Amendments do not meet the standards set forth in Sections 38561(a) and 38562(e), as they continue to include inaccurate CI values for corn ethanol, cane ethanol, and electricity. (See Exhibit "A.") If a CI sends the wrong "signal" to downstream regulated parties, then the LCFS regulation will result in the use of pathways that may increase GHG emissions above the levels that would result if the best possible CI values had been assigned to various renewable-fuel pathways in the regulation. (See Exhibit "A.") While a small number of these issues were resolved through the Proposed Modifications, a review of the 15-Day Notice has revealed additional concerns with respect to the CI values proposed by CARB staff, which likewise would send the wrong "signals" and result in the greater use of higher CI fuels. FF56-13

A. Calculation of Direct Emissions from Corn Ethanol & Sugarcane Ethanol [CA-GREET 3.0]

Growth Energy has reviewed CARB's calculation of direct emissions for corn ethanol, which continue to be overstated. First, for its rail energy use, CARB has added the same amount of energy as backhaul energy for rail movement. This overstates rail emissions because the energy use for rail already includes backhaul energy. (See Exhibit "A" at 2.) Rail emissions are also overstated because they erroneously include the same energy use for both loaded and empty cars. (*Id.*) FF56-14

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Road emissions for corn ethanol are likewise overstated. The new version of CA GREET has changed the load size and fuel economy of vehicles in a manner unsupported by the evidence. For example, the energy use contemplated for certain heavy duty unloaded vehicles is 79.3% of the loaded vehicles, while U.S. DOE studies show the same loaded vehicles are three times the weight of unloaded vehicles (meaning that the energy use of unloaded vehicles should be closer to approximate 33% of a loaded vehicle). (See Exhibit "A" at 2.) U.S. DOE data likewise shows that backhaul (unloaded) energy use for medium duty vehicles is approximately 50-66% of loaded energy (compared to 79.3%). (*Id.*) FF56-15

Moreover, despite the extensive comments previously provided for cane ethanol, which demonstrated the CI for cane was understated by approximately 5.5 g/MJ, the Proposed Modifications contain no revisions to correct this erroneous CI value. (*Cf.* April 27, 2018, Comments at 12-15.) FF56-16

B. Calculation of Indirect Land Use Emissions to Reflect Current GTAP

Growth Energy also notes the Proposed Modifications do not include many of the revisions requested in its April 27, 2018, comments relating to indirect land use emissions. Such revisions are particularly important with respect to CARB's continued use of an outdated GTAP model. Specifically, researchers at Purdue University updated the GTAP model in 2017, and those updates were reported in the peer review literature in July 2017. That model has been available to the public and CARB for an entire year, and includes many updates that correct known errors and inaccuracies in the prior model. (See Exhibit "A" at 1.) By failing to update its indirect land use change values to reflect the current version of the GTAP, the Proposed Amendments are not based on the "best available scientific information," (Health & Saf. Code, § 38562, subd. (e)), and also fail to achieve the "maximum technologically feasible and cost- FF56-17 effective reductions in greenhouse gas emissions." (See Health & Saf. Code, § 38560.5, subd. (c).) FF56-17 cont.

C. **Treatment of Electricity under the LCFS Regulation**

The LCFS uses an "Energy Economy Ratio" ("EER") to account for differences in energy efficiency among different types of fuels and vehicles, which is "defined as the ratio of the number of miles driven per unit energy consumed for a fuel of interest to the miles driven per unit energy for a reference fuel." (2009 ISOR at ES-18.) Following a review of the new information regarding the EERs in the 15-Day Notice, and the Proposed Modifications, Growth Energy has determined that several additional issues should be corrected:

- The 15-Day Notice states the estimated average efficiency for cargo handling equipment is 38%, but this is unrealistic and unsupported by the record. Indeed, the maximum efficiency (the highest possible percentage) for diesel engines is 41-42%. (See Exhibit "C" at 2.) FF56-18

- The hours of operation by equipment type for cargo handling vehicles is unclear. Table 1 of Appendix D lists the hours of operation by vehicle type, and includes "hours" ranging from 1,900 to 401,633. The Table does not state annual use rate, and it is unclear what these values refer to. (See *id.*) FF56-19

- The EER for Ocean Going Vessels ("OGV") presumes all California ports will rely upon the local utility, without accounting for the fact that some ports generate their own electricity. (See *id.*)

- The EER for OGVs at berth does not account for the generation of electricity from boilers. (See *id.*) FF56-20

- The EER of 2.6 for OGVs is not supported by substantial evidence in the record, as this figure does not appear to be based on any computation of electrical power generated by OGVs. (See *id.* at 3.)

To ensure the CI values assigned to electricity are based on the "best available economic and scientific information," and reliable data and methodologies, CARB should correct these issues before adopting the Proposed Amendments. FF56-21

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II. Treatment of Infrastructure Capacity Credits

A. If CARB Issues Credits for Electricity and Hydrogen Capacity, it should also Issue Credits for Biofuel Infrastructure

As explained below, CARB should not consider the Proposed Modifications, as AB 32 and SB 32 do not authorize credits for underutilized capacity that is not tied to actual greenhouse gas emissions reductions. (See *infra* at § II.C.) In the event CARB does consider the Proposed Modifications, however, CARB should include infrastructure capacity credits for ***all*** low CI alternative fuels.

CARB has no rational basis to treat electricity and hydrogen in a manner different from other alternative fuels. While electricity and hydrogen have relatively low CI values, and CARB has stated a need to increase infrastructure associated with the delivery of those fuels to end-users, the same can be said for a wide-range of other fuels. Indeed, numerous alternatives fuels have a similar or lower CI value than electricity and hydrogen (even when EERs are included), while the use of those fuels is likewise limited by infrastructure. There is no lawful basis articulated in the record for this differential treatment of alternative fuels across the LCFS regulation, much less a rational basis. FF56-22

As such, to the extent CARB considers providing credits for generating capacity for electricity and hydrogen, it should do the same for all low-CI alternative fuels.

B. The Proposed Amendments and the EA Should Receive Additional Public Comment

1. The Proposed Modifications Are Not Sufficiently Related to the Original Text of the Proposed Amendments

FF56-23

California law provides that "[n]o state agency may adopt, amend or repeal a regulation which has been changed from that which was originally made available to the public . . . unless the change is . . . ***sufficiently related*** to the original text that the public was adequately placed on

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notice that the change could result from the originally proposed regulatory action." (Govt. Code, § 11346.8(c) [emphasis added].) To be "sufficiently related," changes must be such that "a reasonable member of the directly affected public could have determined from the [original text of the] notice that these changes to the regulation could have resulted." (1 C.C.R., § 42.)

Growth Energy is concerned the Proposed Modifications do not satisfy this standard, as it appears that "a reasonable member of the directly affected public could [***not***] have determined from the [original text of the] notice that these changes to the regulation could have resulted." (1 C.C.R., § 42.) Until the Proposed Modifications were released, the LCFS previously focused exclusively on provisions that seek to achieve ***actual*** greenhouse gas emissions reductions. The proposed Zero Fueling Infrastructure Crediting Provisions, however, abandon this approach, and seek instead to award credits for capacity, regardless of whether actual greenhouse gas reductions are achieved. As a result, CARB staff has acknowledged these modifications are "certainly a philosophical departure from what the program has been about in the past . . . ." (Exhibit "D"; see also June 11, 2018 CARB Workshop [statements by CARB Staff] [recognizing the Proposed Modifications reflect a "departure from fuel neutrality," and "go above and beyond what [CARB has] issued credits for in the past"].) Other commenting parties have observed that these changes represent a "paradigm shift" and a "clear departure from the concept that a ton [of emissions] is a ton [of emissions]." (June 11, 2018 CARB Workshop [statements by commenters in attendance].) FF56-23 cont.

No "reasonable member of the directly affected public" could have anticipated the Proposed Modifications following a review of the original text of the March 6, 2018 Notice of Proposed Amendments to the LCFS ("Notice"). (1 C.C.R., § 42.) The Notice states:

> Staff believes that the lack of fuel pathways that combine zero carbon electricity and ZEV fueling technology is due to the small geographic

> footprint of ZEV infrastructure—which is often located in dense urban areas—making it difficult to co-locate renewable power generations with fueling stations. To address this issue, staff proposes to allow renewable power generated in the same balancing authority as the ZEV load to be used in EV charging and H2 production . . . . Additionally, staff is proposing an option to recognize and reward the GHG benefits of shifting EV charging and electrolytic hydrogen load to the periods of time when intermittent renewable electricity might otherwise be wasted (curtailed) . . . . These amendments are intended to promote the expansion of zero-emission vehicle infrastructure through the Low Carbon Fuel Standard Program as directed by Executive Order B-48-18.

(March 6, 2018 Notice of Proposed Amendments at 6-7.) FF56-23 cont.

There is nothing in the original Notice that could reasonably apprise the interested public that CARB would be departing from a paradigm under which the LCFS provides credits for actual GHG emissions reductions. (1 C.C.R., § 42.) The Notice suggested that CARB would be promoting infrastructure by (i) "allow[ing] renewable power generated in the same balancing authority as the ZEV load to be used in EV charging and H2 production," and (ii) recognizing and rewarding regulated parties that shifted "EV charging and electrolytic hydrogen load to the periods of time when intermittent renewable electricity might otherwise be wasted (curtailed) . . . ." (*Id.*) Plainly, both of these measures were based on providing credits for ***actual usage***.

Now, in contrast, CARB seeks to untether credits from actual emissions reductions, and instead award credits for unused capacity. This is not only fundamentally different than the measures identified in the original Notice to promote infrastructure, but represents a wholesale change in the way the LCFS has been structured since its original promulgation in 2009. As CARB staff acknowledged at the workshop regarding the Proposed Modifications, the changes represent a "departure from the framework and philosophy of the program historically." (June 11, 2018 CARB Workshop [statements by CARB staff].) Because the Proposed Modifications represent a paradigmatic change in the LCFS, and there was no mention in the original Notice of the issuance of credits for unused infrastructure capacity, "a reasonable member of the directly affected public could [***not***] have determined from the [original text of the] notice that these changes to the regulation could have resulted." (1 C.C.R., § 42.) As such, the Proposed Modifications are not "sufficiently related to the original text," (Govt. Code, § 11346.8(c)), and the Proposed Modifications should be circulated for a full 45-day review period.[1]

This is consistent with related federal case law interpreting parallel provisions in the federal Administrative Procedure Act. (See California Practice Guide, Administrative Law: Rulemaking and Open Government, at 23-58.) For example, in *Chocolate Manufacturers Association of United States v. Block* (4th Cir. 1985) 755 F.2d 1098, the Fourth Circuit held that the Department of Agriculture's proposed rulemaking did not provide adequate notice that elimination of flavored milk from the Special Supplemental Food Program for Women, Infants and Children ("WIC Program") would be considered in the rulemaking procedure.

FF56-23 cont.

As the Fourth Circuit explained, "[t]he requirement of notice and a fair opportunity to be heard is basic to administrative law." (*Id.* at 1102.) "The notice-and-comment procedure encourages public participation in the administrative process and educates the agency, thereby helping to ensure informed agency decisionmaking." (*Id.* at 1103 [quoting *National Tour Brokers Ass'n v. United States* (D.C. Cir. 1978) 591 F.2d 896, 902] [internal citations omitted].) Thus, "[a]lthough an agency, in its notice of proposed rulemaking, need not identify precisely every potential regulatory change, the notice must be sufficiently descriptive to provide interested parties with a fair opportunity to comment and to participate in the rulemaking." (*Id.*

1 Such a dramatic shift in the operation of the LCFS regulation deserves robust public input. Despite this, CARB published the 15-day notice on June 20, 2018, ensured the deadline for comments on the Proposed Amendments would fall on July 5, 2018, immediately after the July 4th holiday, and inclusive of two weekends. Consequently, the regulated public's ability to contribute to the rulemaking process on this issue was severely truncated.

at 1104 [internal citations omitted].) Accordingly, notice is adequate if the changes "are ***in character with the original scheme***" and the final rule is a "***logical outgrowth***" of the notice. (*Id.* [emphasis added].)

In finding the notice was inadequate, the Fourth Circuit emphasized that, "for many years the Department of Agriculture has permitted the use of chocolate in some form in the food distribution programs that it administers," and that in all of the proposed rulemaking documents "the Department never suggested that flavored milk [might] be removed from the WIC Program." (*Id.* at 1106.) Based on these facts, the Fourth Circuit concluded that "it cannot be said that the ultimate changes in the proposed rule were in character with the original scheme or a logical outgrowth of the notice." (*Id.* at 1107.)

FF56-23 cont.

Here, as in *Chocolate Manufacturers*, the final rule included a provision that has reversed a long-standing policy of the agency concerning its regulatory program. As with the Department of Agriculture's policy of permitting the use of chocolate in its food distribution programs, CARB's long-standing policy of offering credits only for actual GHG emissions reductions meant that the public could not anticipate a contrary course of action absent specific notice of the agency's intent. Yet here, as in *Chocolate Manufacturers*, CARB "never suggested" in its rulemaking notice that the agency might propose offering credits for infrastructure capacity. Consequently, CARB's inclusion of regulations providing capacity credits for ZEV infrastructure is neither "in character with the original [LCFS] scheme" nor a "logical outgrowth" of the rulemaking notice. (*Id.* at 1104.) And, to make matters worse, CARB issued the 15-day notice on June 20, 2018, ensuring the comment deadline was the day after the Fourth of July holiday (and, in addition, would include two weekends), severely limiting the ability of the public to review and comment on the proposed change.

CARB's decision to proceed with a 15-day notice for the Proposed Modifications is not only unfair to the regulated public, but also detrimental to the efficiency and integrity of the rulemaking process. To ensure interested parties are provided sufficient time to understand the implications, both intended and unintended, of CARB's proposal, and to provide thoughtful and intelligent comments on the proposal, CARB should instead issue a second 45-day notice that specifically puts the public on notice of the agency's intent to offer credits for infrastructure capacity. FF56-23 cont.

2. The Proposed Modifications Constitute "Significant New Information" and Render the Project Description Unstable

a. The Proposed Modifications Constitute "Significant New Information" under Section 15088.5 of the CEQA Guidelines

California law requires a lead agency to recirculate an environmental document when "significant new information" is added after the original public comment period, "but before certification." (CEQA Guidelines, § 15088.5(a); see also Pub. Resources Code, § 21092.1.) FF56-24

When a lead agency adds "significant new information," the agency must pursue an additional round of consultation. (*Laurel Heights Improvement Assn. v. Regents of University of California* (1993) 6 Cal.4th 1112, 1130 ["*Laurel Heights II*"].) The purpose of requiring recirculation is to encourage meaningful public comment. (*Mountain Lion Coalition v. Fish & Game Commission* (1989) 214 Cal.App.3d 1043, 1053.) As the Supreme Court explained, "new information that demonstrates that an EIR commented upon by the public was so fundamentally and basically inadequate or conclusory in nature that public comment was in effect meaningless triggers recirculation." (*Laurel Heights II*, *supra*, 6 Cal.4th at 1130.)

"'To facilitate CEQA's informational role, the EIR must contain facts and analysis, not just the agency's bare conclusions or opinions.' [Citations.] An EIR must include detail sufficient to enable those who did not participate in its preparation to understand and to consider meaningfully the issues raised by the proposed project." (*Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal.3d 376, 404-405 ["*Laurel Heights I*"].) If an agency adds significant new information, the agency must recirculate a revised EIR, "so that the public is not denied an opportunity to test, assess, and evaluate the data and make an informed judgment as to the validity of the conclusions to be drawn therefrom." (*Save Our Peninsula Committee v. Monterey County Bd. of Supervisors* (2001) 87 Cal.App.4th 99, 131.)

While new information is not "significant" when it "merely clarifies or amplifies or makes insignificant modifications in an adequate" environmental document, CEQA requires recirculation when the environmental analysis will be "changed in a way that deprives the public of a meaningful opportunity to comment upon a substantial adverse environmental effect of the project or a feasible way to mitigate or avoid such an effect . . . ." (CEQA Guidelines, § 15088.5(a).) Section 15088.5 enumerates several examples of what constitutes "significant new information," but that list is not intended to be exhaustive. For instance, Section 15088.5 requires recirculation where (i) the new information discloses a new environmental effect or a substantial increase in the severity of a previously-recognized environmental effect, (see *id.*, subds. (a)(1), (a)(2)); (ii) mitigation measures or alternatives "considerably different" from those previously analyzed would lessen a project's environmental effects, but the proponent declines to adopt such measures/alternatives, (see *id.*, subd. (a)(3)); and (iii) the environmental document is "so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded." (*Id.*, subd. (a)(4).)

FF56-24 cont.

In this case, the 15-Day Notice reveals that CARB is seeking to change fundamental aspects of the "project" under CEQA. Specifically, since 2009, the LCFS been focused on providing credits for actual greenhouse gas emissions reductions. The proposed Zero Fueling Infrastructure Crediting Provisions, however, would provide credits for mere capacity rather than actual use. Providing credits for unused capacity will not achieve the same greenhouse gas or criteria pollutant emissions benefits as the existing LCFS.

This change in the LCFS warrants recirculation for several reasons. First, with respect to the discussion of a project that includes credits for capacity for electric and hydrogen infrastructure, the environmental analysis is currently silent; there is simply no discussion in the environmental document about this new and fundamentally changed aspect of the project. As such, Growth Energy is concerned that CARB's discussion of the issuance of credits for capacity for electric and hydrogen infrastructure may be "so fundamentally and basically inadequate and conclusory in nature that meaningful public review and comment were precluded." (CEQA Guidelines, § 15088.5, subd. (a)(4).) FF56-24 cont.

Moreover, CARB's new proposal has the potential to result in new environmental effects or a substantial increase in the severity of a previously-recognized environmental effect. (See CEQA Guidelines, § 15088.5, subds. (a)(1), (a)(2).) First, the entire purpose of the Proposed Modifications is to increase the number of hydrogen and DC fast charging stations that are constructed in California. CARB has previously admitted in its existing EA for the Proposed Amendments that the potential environmental effects associated with the construction of ***other*** facilities – *i.e.*, new or modified facilities to ***produce*** alternative fuels – constitutes a significant and unavoidable environmental effect. (See EA at 101-02.) Although it is not the public's burden to demonstrate a project would have potential environmental effects, (*Sundstrom v. County of Mendocino* (1988) 202 Cal.App.3d 296, 311 ["CEQA places the burden of environmental investigation on government rather than the public," and a lead agency "should not be allowed to hide behind its own failure to gather data."]), the evidence shows new hydrogen and DC fast charging stations could lead to potentially significant environmental effects (including, inter alia, aesthetics, air quality, biological resources, cultural resources, geology and soil, hydrologic resources, noise, and traffic and transportation). (See Exhibit "C" at 2.) Indeed, the Draft EA expressly notes that the construction of hydrogen and DC fast charging stations – which were not directly incented under the original proposal – would have potentially significant impacts: FF56-24 cont.

> Generally, it is expected that during the construction phase for any facilities, criteria air pollutants and toxic air contaminants (TACs) could be generated from a variety of activities and emission sources. These emissions would be temporary and occur intermittently depending on the intensity of construction on a given day. Site grading and excavation activities would generate fugitive particulate matter (PM) dust emissions, which is the primary pollutant of concern during construction. Fugitive PM dust emissions (e.g., respirable particulate matter [PM10] and fine particulate matter [PM2.5]) vary as a function of several parameters, such as soil silt content and moisture, wind speed, acreage of disturbance area, and the intensity of activity performed with construction equipment. Exhaust emissions from off-road construction equipment, material delivery trips, and construction worker-commute trips could also contribute to short-term increases in PM emissions, but to a lesser extent. Exhaust emissions from construction-related mobile sources could also result in short-term increases in CO, CO2, hydrocarbons, PM, reactive organic gases (ROG), and nitrogen oxides (NOx). These emission types and associated levels fluctuate greatly depending on the particular type, number, and duration of usage for the varying equipment.

(EA at 128.) In other words, the Proposed Modifications would result in new or increased significant effects that CARB has previously conceded would occur. (See CEQA Guidelines, § 15088.5, subds. (a)(1), (a)(2).)

In addition, as explained in Growth Energy's April 27, 2018, comments on the Proposed Amendments, it is critically important that CARB use scientifically defensible CI values that will result in actual emissions reductions, based on the "signals" to downstream regulated parties. If CARB sends the wrong signals, and incentivizes the use of higher CI fuels, greenhouse gas

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emissions would be higher. Here, by providing credits for infrastructure and capacity, CARB is lessening the value of credits for other lower CI fuels, and increasing the value of credits for electrical generation and hydrogen. By sending these inaccurate signals, and untethering credits from actual emissions reductions, any greenhouse gas benefits associated with the LCFS will be substantially less than contemplated in the EA. Likewise, the Proposed Modifications have the potential to displace lower CI fuels with alternative fuels with higher CI values, and bring into question whether CARB can meet the emissions reductions contemplated under SB 32.

Growth Energy is unaware of any analysis CARB has performed with respect to how many tons per year of greenhouse gas emissions would be lost as a result of the generation of credits for electricity and hydrogen capacity. However, using CARB's own Illustrative Compliance Scenario, Growth Energy's experts have found that capacity credits equal to 5% of deficits could result in "potential lost benefits for calendar year 2020 alone to amount to approximately 820,000 metric tons" of greenhouse gas emissions. (Exhibit "B" at 1.) FF56-24 cont.

Further, the Proposed Modifications amend the sunset date for NOx mitigation in a manner that could have potentially significant environmental effects. In the EA, CARB analyzed the Proposed Amendments, which originally contemplated an extension of the sunset date for NOx mitigation until such time that at least 90% of the hours of operation of diesel fueled engines were accumulated by so-called "New Technology Diesel Engines" (NTDEs). (EA at 24; ISOR at EX-7, -13.) The Proposed Modifications change the phase-out provisions significantly, contemplating separate sunset dates for the biodiesel NOx mitigation requirements for on-road and non-road diesel vehicles and engines. (15-Day Notice at 23.) Yet the EA was not modified to address this issue. FF56-25

The EA should be augmented. First, as explained in prior comments, CARB's assumption that there is no increase in NOx emissions from NTDEs is not supported by substantial evidence. Thus, shortening the end of the mitigation period for on-road diesel vehicles would increase NOx emissions. (See Exhibit "C" at 5.) In addition, there is nothing in either the Proposed Amendments or the Proposed Modifications that, following the sunset date for one category of vehicles, would prohibit biodiesel without mitigation to be introduced into the other category of vehicles or engines that have not yet reached the sunset date. (*Id.* at 5.) This introduction of non-mitigated biodiesel into non-NTDE engines would increase NOx emissions. This is of even greater concern because "the reporting requirements of the ADF regulation do not make any distinction between bio-diesel blends intended for use as on-highway or non-road fuels and there is no explicit prohibition or enforcement mechanism in the ADF regulation against introducing non-mitigated on-highway diesel fuel into any non-road engine." (*Id.*) Thus, by disaggregating the sunset dates, the Proposed Modifications would have potentially significant environmental effects as to NOx emissions. FF56-25 cont.

In short, because the EA does not address the fundamental shift in the regulatory approach taken with respect to the generation of credits embodied by the Proposed Modifications, and because the construction of new and modified infrastructure for electric and hydrogen fuel stations has the potential to result in new environmental effects or a substantial increase in the severity of a previously-recognized environmental effects, the EA should be revised to include the Proposed Modifications as part of the "project," and recirculated for public review.[2] (See CEQA Guidelines, § 15088.5, subds. (a)(1), (a)(2).) FF56-26 continue to footnote on next page

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[2] The environmental document should also be recirculated because members of the public, including Growth Energy, proposed numerous alternatives and mitigation measures "considerably different" from those previously analyzed that would lessen the significant

b. The Project Description is Unstable Because the EA Evaluates a Different Project than what is now Being Proposed

A lead agency's environmental document under CEQA must include a clear and comprehensive description of the proposed project; this is critical for the agency to perform an accurate analysis of impacts and meaningful public review. (*County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 193 ("*Inyo II*"). As explained in *Inyo II*: FF56-27

> A curtailed or distorted project description may stultify the objections of the reporting process. Only through an accurate view of the project may affected outsiders and public decision-makers balance the proposal's benefit against its environmental cost, consider mitigation measures, assess the advantage of terminating the proposal (*i.e.*, the "no project" alternative) and weigh other alternatives in the balance.

(*Id.* at 192-93.) "A curtailed, enigmatic or unstable project description draws a red herring across the path of public input." (*Id.* at 197-98; see also *San Joaquin Raptor Rescue Center v. County of Merced* (2007) 149 Cal.App.4th at 655-57 [invalidating an EIR for misleading project description].)

Although CARB has introduced Proposed Modifications that represent a significant "departure from the framework and philosophy of the program historically," (June 11, 2018 ARB Workshop [statements by CARB Staff]; see also Exhibit "D"), CARB did not modify the EA or otherwise discuss the potential environmental effects of the Proposed Modifications. Thus, in its current state, the EA addresses a different "project" under CEQA than what is being proposed and considered by CARB. As such, the project description is neither complete nor accurate. To ensure compliance with CEQA, CARB should modify its environmental analysis to

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environmental effects of the Proposed Amendments; however, CARB has declined to adopt those mitigation measures and project alternatives. (CEQA Guidelines, § 15088.5(a)(3).) FF56-26 continued from footnote on last page

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incorporate the "project" under consideration, and recirculate the EA for public review, prior to its consideration of the Proposed Modifications. FF56-27 cont.

C. The Proposed Modifications are Inconsistent with CARB's Defined Project Objectives, AB 32, and SB 32

The LCFS regulation is an "implementation measure" adopted under the color of AB 32 and SB 32. As such, the LCFS must "achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from those sources or categories of sources, in furtherance of achieving the statewide greenhouse gas emissions limit." (Health & Saf. Code, § 38560.5, subd. (c); see also *id.* § 38562, subd. (a) [including similar language].) SB 32 likewise references CARB's mandate to adopt "rules and regulations to achieve the maximum technologically feasible and cost-effective greenhouse gas emissions reductions . . . ." (Health & Saf. Code, § 38566.) FF56-28

The Proposed Modifications are inconsistent with these objectives. The Proposed Modifications would "effectively decrease the actual GHG reductions associated with the LCFS program by up to 5%." (Exhibit "B" at 1.) Thus, assuming the LCFS actually reduces greenhouse gas emissions,[3] it is unclear how the Proposed Modifications can be reconciled with the Legislature's mandate that the LCFS "achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions . . . ." (Health & Saf. Code, § 38560.5, subd. (c); see also *id.* § 38562, subd. (a) [including similar language].) To the extent the Proposed Modifications are not consistent with the Legislature's mandate, their adoption constitutes an *ultra vires* act.

[3] Growth Energy notes that, as explained previously, the phenomenon of fuel-shuffling reduces, if not eliminates, the greenhouse gas emissions benefits associated with the LCFS. (April 27, 2018, Comments of Growth Energy at 48-49.)

There is likewise no practical need for the LCFS to provide credits for unused infrastructure, as any such efforts would be largely duplicative of concurrent state efforts to subsidize hydrogen station construction and the deployment of DC fasting charging stations. (See Exhibit "B" at 3-4.) In essence, the provision of credits for hydrogen and electric charging infrastructure would amount to little more than providing entities credits for infrastructure that is already being largely funded by the State. (*Cf.* Government Code § 11342.2 ["[N]o regulation adopted is valid or effective unless consistent and not in conflict with the statute and reasonably necessary to effectuate the purpose of the statute."].)

Growth Energy understands CARB may claim the Proposed Modifications are required under Executive Order B-48-18. While Executive Order B-48-18 arguably directs CARB to "[r]ecommend ways to expand zero-emission vehicle infrastructure through the Low Carbon Fuel Standard Program," the executive order does not require the generation of credits for infrastructure based on unused capacity as opposed to actual utilization. And even if Executive Order B-48-18 could be read as mandating the issuance of credits for capacity regardless of actual utilization, the executive order would be contrary to AB 32 and SB 32, as explained above. FF56-28 cont.

The Proposed Modifications are also inconsistent with CARB's articulated project objectives. While the EA states that the goal of the Proposed Amendments is to "strengthen the CI reduction targets through 2030" to comply with SB 32, and to "reduce the CI of transportation fuels in the California market," the Proposed Amendments bear no direct relation to any reduction in CI; rather, they are based solely on capacity without respect to actual utilization. (*Cf.* EA at 15.) Moreover, while CARB has stated that one of its project objectives is to "provide greater innovation and development of cleaner fuels," (*cf. id.*) – and has specifically rejected alternatives on this basis in the past, (see Exhibit "B" at 3-4) – the Proposed Modifications seek to provide uneven benefits to certain existing technologies, while at the same time ignoring infrastructure needs for other low-CI alternative fuels. Thus, the Proposed Modifications appear to undermine CARB's own stated objectives.[4]

FF56-28 continued from last page, continues to footnotes below

Because the Proposed Modifications are inconsistent with AB 32 and SB 32, as well as the project objectives, CARB should decline to consider the Proposed Modifications.[5]

D. CARB Should Adopt the E15 Alternative Instead of the Proposed Modifications

In its April 27, 2018, comments, Growth Energy proposed an "E15 Alternative," under which CARB would concurrently adopt fuel specifications for E15, and incorporate E15 into the LCFS. Because E15 is a low CI fuel and is actively being used in at least 28 states, using a greater percentage of ethanol would help reduce greenhouse gas emissions "to at least 40 percent below the statewide greenhouse gas emissions limit no later than December 31, 2030," in a manner that is both technologically feasible and cost-effective. (Health & Saf. Code, § 38566; see generally April 27, 2018, Comments of Growth Energy at 23-24, 57-58.)

FF56-29

As explained in the expert materials submitted herewith, "it is easy to assess the potential GHG reduction benefits from allowing E15 to be sold in California." (Exhibit "B" at 3.) For example, using "CARB's LD/High ZEV/20% scenario for calendar year 2020, and assuming that

[4] CARB has previously declined to consider alternatives to the LCFS regulation because they do not meet CARB's project objective of "provid[ing] greater innovation and development of cleaner fuels." (*Cf.* EA at 15.) Based on the fact that the Proposed Modifications would undermine this project objective, CARB should (i) remove fostering innovation as a project objective, and/or (ii) fully consider each of the project alternatives that CARB has previously rejected on the basis that those alternatives would allegedly not foster innovation to the same as the LCFS regulation.

[5] Notably, the 15-Day Notice makes no reference to the project objectives articulated in the ISOR or the EA; much less any analysis of whether the Proposed Modifications meet the project objectives.

FF56-28 continued from above

the credits generated only by starch ethanol increase by 50% (given that the volume of ethanol used will increase by 50% going from E10 to E15), the resulting reduction in GHG emissions would equal 1,126,000 metric tons of GHG emissions from increased use of ethanol plus a further reduction of another 760,000 metric tons of GHG emissions due to reduced use of petroleum based gasoline blendstocks."[6] (See Exhibit "B" at 3-4.) The Proposed Modifications, in contrast, would ***increase*** greenhouse gas emissions compared to the original Proposed Amendments. Thus, in addition to being a "more effective and less burdensome" alternative that (i) meets the legislative objective of reducing greenhouse gases, (see Govt. Code, § 11346.9, subd. (a)(4)), and (ii) avoids the LCFS's potentially significant environmental effects, (see generally Pub. Resources Code, § 21001), the adoption of the E15 alternative would further – and not undermine – CARB's statutory mandate. **FF56-29** continued from last page, continues to footnotes below

As a result of the foregoing, CARB should incorporate the E15 Alternative as a project alternative under CEQA, and approve the E15 alternative instead of the Proposed Amendments. (See Govt. Code, § 11346.9, subd. (a)(4); Pub. Resources Code, § 21001; CEQA Guidelines, §§ 15043.)

E. The SRIA Should Be Augmented to Address Impacts Associated with The Proposed Modifications' Dilution of the Value of Credits

The APA requires that state agencies proposing to "adopt, amend, or repeal any administrative regulation" must perform an assessment of "the potential for adverse economic impact on California business enterprises and individuals." (Govt. Code, § 11346.3, subd. (a).) The APA requires, *inter alia*, that CARB prepare a SRIA analyzing "the potential adverse **FF56-30**

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6 In addition to reducing the greenhouse gas emissions benefits associated with the Proposed Amendments, the Proposed Modifications would also reduce the alleged criteria pollutant emissions benefits of the ADF regulation – including NOx emissions. (See Exhibit "B" at 4.) The EA, however, does not address this issue. **FF56-29** continued from above

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economic impact on California business and individuals of a proposed regulation," (Govt. Code, § 11346.3), and declare in the notice of proposed action any initial determination that the action will not have a significant statewide adverse economic impact directly affecting business. (Govt. Code, § 11346.5, subd. (a)(8); *WSPA v. Board of Equalization* (2013) 57 Cal.4th 401, 428.)

The SRIA should be revised to include impacts associated with the Proposed Modifications. Specifically, the economic impact of providing credits for unused fuel capacity at hydrogen and DC fast charge stations must be considered. As noted by Growth Energy's experts, using a very conservative (*e.g.*, low) assumed value of $100 per LCFS credit, the value of LCFS credits awarded for unused capacity at hydrogen and DC fast charge could amount to as much as $82 million in a single year (2020), and the cumulative value of all credits awarded over period allowed under the Proposed Amendments by CARB is likely to much greater. Further, by providing credits for unused infrastructure, the Proposed Amendments "will decrease the value of LCFS credits generated by other means that do in fact result in actual reductions in GHG emissions." (Exhibit "B" at 2.) This is because "the 'capacity' credit provisions will artificially increase the supply of LCFS credits for which there is a finite demand which in turn will decrease the value of all LCFS credits" relative to what it would have otherwise been. (*Id.*) This devaluing of credits will impact credit holders, and decrease the alleged benefits identified in the Proposed Amendments.

FF56-30 cont.

To avoid these impacts, the Proposed Modifications should not be adopted. But if they are, CARB should first revise the SRIA and accurately assess the economic impacts of the Proposed Modifications.

III. CARB Should Continue to Review the Proposed Amendments

A. CARB Staff Should Undertake a Peer Review to Evaluate the "Scientific Portions" of the Proposed Modifications (Health & Saf. Code, § 57004(b))

Section 57004(d) of the Health and Safety Code states that CARB shall not "take any action to adopt the final version of a rule unless" it undertakes a peer review to evaluate the "scientific portions" of the rule. (Health & Saf. Code, § 57004(d).) However, none of the rulemaking materials submitted with the 15-Day Notice show that CARB retained a peer reviewer to evaluate the Proposed Modifications (or the Proposed Amendments).

Peer review of the Proposed Modifications is required, as the new text is premised upon, or derived from, empirical data or other scientific findings, conclusions, or assumptions establishing a regulatory level, standard, or other requirement for the protection of public health or the environment." (*Id.*, subd. (a)(2).) These "scientific portions" include, but are not limited to: FF56-31

- The extent to which new hydrogen and DC fast charging stations receiving credits under the LCFS would be utilized;
- Whether the issuance of credits for unused capacity would result in direct decreases in greenhouse gas emissions;
- Whether the issuance of credits for unused capacity would decrease the greenhouse gas and criteria pollutant emissions benefits of the LCFS;
- The extent to which the development of new hydrogen and DC fast charging stations would result in environmental effects;
- Whether NTDE engines, in fact, result in no increase in NOx emissions when operated on biodiesel;
- Whether disaggregating the sunset dates for mitigation of NOx increases from biodiesel used in non-road and on-road diesel engines would increase NOx emissions;
- CARB's decision to provide credits for hydrogen and electric charging infrastructure, but not infrastructure for other low carbon fuels;

- The use of an updated GTAP to calculate indirect land use change;
- The energy use attributed to transport of corn ethanol by rail;
- The energy use attributed to transport of corn ethanol by road;
- The EER for cargo handling vehicles;
- The EER for ocean going vessels; and
- Whether the issuance of credits for capacity would dilute the value of shares for actual greenhouse gas emissions reductions.

FF56-31 cont.

B. CARB Should Address the Issues Previously Raised by Growth Energy

Growth Energy previously submitted comments on the Proposed Amendments on April 27, 2018. Growth Energy, however, has noted that very few of the issues raised in the April 27, 2018, comments have been corrected. While Growth Energy understands CARB must "summarize and respond to the comments" before "taking final action on" the proposal, (17 Cal. Code Regs., § 60007(a)), Growth Energy believes nearly all of the comments warranted corrections that should be incorporated into the final version of the Proposed Amendments. As a result, Growth Energy requests that CARB revise the Proposed Amendments and/or the EA to address the issues previously raised in the April 27, 2018, comment letter. These issues include:

FF56-32

- **CA-GREET 3.0**
  - The most current version of the GREET model includes a distillers' grains (DDG) methane avoidance credit, which equals 2.1 g/MJ, and is not incorporated into CA GREET 3.0 under the Proposed Modifications. FF56-33
  - Although the ISOR estimates that the CI for corn ethanol will drop from approximately 70 g/MJ to 45 g/MJ, it is unclear what evidence the Executive Officer relied upon to determine corn ethanol facilities would install CCS systems at a rate necessary to reduce their CI to 45 g/MJ. As a result, Growth Energy urges CARB to swiftly consider the approval of the proposed pathways for such fuel to help provide evidentiary support for CARB's 45 g/MJ estimate. FF56-34

- The CI for corn starch ethanol under CA GREET 3.0 contains a value for the electricity that is used in transportation and distribution with an emission factor developed using US average power, even though most such emissions are likely to be in California. FF56-35

- The CI for sugarcane is understated because the nitrogen content of biomass and fertilizer for sugarcane are far higher than estimated by CARB. FF56-36

- CA GREET 3.0 uses the same emission factor for truck transport in Brazil and California, even though Brazil should be higher. FF56-37

- CA GREET 3.0 uses simplified calculators for corn ethanol and sugarcane ethanol that contain several errors. Unless corrected, the CI for sugarcane ethanol will be understated, and the CI for corn will be overstated. FF56-38

- **Calculation of Indirect Land Use Emissions ("ILUC")**
  - Using CARB's AEZ-EF model in conjunction with GTAP to estimate emissions associated with the various land use changes, researchers have determined that the ILUC for corn starch ethanol should be reduced from 19.8 g/MJ to 10.3 g/MJ. FF56-39
  - The current ILUC for corn starch ethanol is based on 2011 conditions, which correspond to a drought year in the U.S. that negatively impacted corn yields. When a three-year average is used, the ILUC should be reduced significantly. FF56-40

- **Energy Economy Ratio ("EER")**
  - The EER for electricity is far too high because the estimates were generated based on testing performed with accessory modes off. FF56-41
  - The EER for electricity is also too high because it is based on optimal temperature (75°-80°) for battery efficiency, and not real world conditions. FF56-42
  - The EERs for numerous vehicles are overstated. FF56-43

- **Treatment of Renewable Electricity for Fuel Pathways**
  - The Proposed Amendments do not allow CI reduction for dedicated renewable electricity unless the generation facilities are co-located with the fuel production facility, removing incentives for fuel producers to develop renewable sources for process energy. FF56-44
  - The proposed Zero Fueling Infrastructure Crediting Provisions provide credits for capacity rather than actual use. Providing credits for capacity will not achieve the same GHG or criteria pollutant benefits as the existing LCFS. FF56-45

- **Analysis of Alternatives Under the Government Code**
  - CARB should consider the WSPA Alternative which contemplates that GHG emissions currently attributable to the LCFS program would "instead be achieved by the Assembly Bill (AB) 32 Cap and Trade Program in the most cost-effective manner to address GHG emissions." FF56-46
  - CARB should consider the E15 Alternative under which CARB would concurrently adopt fuel specifications for E15 and incorporate E15 into the LCFS. FF56-47
- **Adequacy of Economic Analysis in the SRIA**
  - The current SRIA does not meet the applicable standards under the APA. The ISOR's discussion of the "elimination of existing businesses" and "the competitive . . . disadvantages" does not fully address or take into account that the LCFS regulation is projected to increase the price of gasoline. FF56-48
- **External Peer Review**
  - It is unclear whether CARB sought external peer review for: FF56-49
    - The accuracy of each of the components of CA-GREET 3.0, and the effect on the CI for corn ethanol and sugarcane ethanol;
    - The ILUC for corn ethanol;
    - The EER for electricity;
    - The efficacy of NTDEs to reduce NOx emissions from biodiesel;
    - The accuracy of CARB's compliance scenario, including but not limited to the adaptation of alternative jet fuels, solar steam projects, and renewable diesel; and
    - The potential impacts associated with CARB's compliance scenarios, particular with respect to alternative jet fuels, solar steam projects, and renewable diesel.
- **Noncompliance with AB 32**
  - The LCFS regulation has resulted in increased and unmitigated NOx emissions from biodiesel since its inception. There is nothing in the Proposed Modifications that suggests these emissions would be mitigated through the payment of funds to local air districts for NOx mitigation projects. FF56-50

- The proposed mitigation to continuing NOx emissions is not consistent with CEQA. The ISOR's conclusions are based on assumptions concerning industry's use of renewable diesel and alternative jet fuel, and the development of solar steam projects, none of which are required to occur, and all of which are speculative. FF56-51
- The LCFS will result in the construction of new or modified facilities for alternative fuels incentivized by the regulation. FF56-52
- The LCFS regulation will continue to result in fuel shuffling, which increases emissions. FF56-53

- **Requirements of Transparency**
  - CARB must maintain a full and complete rulemaking file:
    - The rulemaking file must include external communications submitted to the staff, the Executive Officer or the Board prior to the date when the rulemaking file is formally opened. If those communications are not included, it should be explained why.
    - Growth Energy urges CARB to take all necessary measures to ensure all external submittals (not within the scope of section 11347.3(b)(7)) concerning this regulatory process have been included in the rulemaking file. FF56-54
    - Growth Energy also urges CARB to ensure all factual information relied upon by CARB staff in connection with the consideration of the Proposed Amendments is included in the rulemaking file.

IV. <u>Conclusion</u>

Thank you for the opportunity to participate in this rulemaking, and your anticipated consideration of the above comments. Growth Energy strongly believes corn ethanol can help CARB in meeting its greenhouse gas reduction targets; however, the regulations CARB considers should be objective in nature and not favor one industry or technology over another. In this regard, the Proposed Modifications exacerbate the existing shortcomings of the LCFS and ADF regulations. FF56-55a As such, CARB should fully address and consider meaningful alternatives to the LCFS regulation (including the WSPA Alternative and the E15 Alternative), and should decline to incorporate the Proposed Modifications into the Proposed Amendments. FF56-55b In the event FF56-56

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CARB considers the Proposed Modifications, CARB should expand capacity credits to all low carbon fuels. FF56-56 cont.

Exhibit “A”

Comments on 15-Day Notice
July 5, 2018
By Thomas Darlington, Air Improvement Resource Inc.
Donald O'Connor, (S&T)[2] Consultants Inc.

The 15-day notice fails to address our 45-day comments on the need to update indirect land use emissions in these current LCFS amendments, and the significant impacts of doing so.

ARB uses the Purdue University GTAP model to evaluate indirect land use emissions. Our comments point out that the current GTAP model which addresses many issues with indirect land use emissions raised over the last few years was developed by Purdue, and reported in the peer reviewed literature in July 2017. The literature indicates that the indirect land use change emissions for corn would have dropped from ARB's current estimate of 19.8 g/MJ to around 10 g/MJ. This model has been available from Purdue for use by ARB since July 2017 (the model is available to the public), and using ARB's previous 30 sensitivity cases for the various input elasticities, it could have generated new indirect land use estimates for all biofuel feedstocks in a few weeks, certainly by September of 2017. The regulatory calendar for the LCFS regulation allowed ample time to use the new, correct GTAP values. Because the Proposed Amendments do not use indirect land use change values from the current GTAP model, the Proposed Amendments are not based on the best available scientific information. FF56-58

Updates to the GREET Model for Corn and Sugarcane

Corn Ethanol

Effects of Distillers Grains on Enteric Fermentation

The modifications proposed in the 15-day notice do not include any revisions addressing our prior comments on distillers' grains reducing enteric fermentation. This is a factor that is included in the GREET2016 model, from which the CA GREET3.0 is derived. The GREET2016 model DG enteric fermentation credit for corn ethanol is estimated at 2,260 g CO2e/mmBTU of ethanol (2.1 gCO2e/MJ). As we pointed out in our prior comments dated April 23, 2018, ARB's main reason for not including this factor appears to be that the animals consuming the DGS rations are not currently in the LCFS LCA ethanol system boundary. However, we previously noted that ARB has made exceptions to boundary conditions for other pathways, and we further pointed out that ARB's position on this is also inconsistent with ISO lifecycle assessment standards. To be consistent with the best available scientific information, the LCFS should be updated to include this DG credit at this time. FF56-59

Transport Emissions

Rail

For rail energy use, ARB has added the same amount of energy as backhaul energy for rail movement. This is not necessary as the energy use for rail is calculated by taking the total fuel used for class 1 railroads and dividing that by the ton-miles of freight moved by those railways. This calculation automatically includes the energy used for back hauls; thus, it is not necessary to double the value. However, even if the backhaul energy was not already included, it would not be the same value as the energy for a loaded car. There is really no justification given for adding the backhaul energy in Attachment C.

FF56-60 continues to footnote below

The ORNL Transportation Energy Data Book Edition 36 reports (Table 9.8) that the total freight moved in 2015 was 1.744 million ton-miles and the energy used by the railroads was 516.4 trillion BTU for a total energy use of 294 BTU/ton-mile which would include the movement of empty cars.[1] CA GREET 3.0 has 274 BTU/ton-mile for loaded and the same energy for unloaded movements. This is not correct and the back haul energy for rail should be removed from the model. The methodology is reported in section 6.2 of Appendix A.

Road

The road energy use in GREET is calculated by taking the vehicle fuel consumption and load and from that calculating the BTU/ton-mile. There is no equivalent data set as exists for the railways where the total fuel used and the total freight moved is available, so the approach in GREET is reasonable. In this version of CA GREET 3.0, however, CARB has changed the load size and the fuel economy without explanation. As a result of the changes, the energy use for a HD truck for corn has been reduced from 3231 BTU/ton-mile to 1574 BTU/ton-mile and the energy use for the back haul is 79.3% of the loaded energy use. This is not accurate. The US DOE reported that a loaded class 8 truck typically weighs three times the unloaded vehicle weight.[2] As a result, back haul energy use should be closer to the ratio of the weight of unloaded vehicle to the fully loaded vehicle that is 33%. There is no explanation for, or evidence to support, the new fuel economy values used by CARB.

FF56-61 continues to footnote below and next page

While the energy use for the heavy-duty trucks decreased, the values for the medium duty trucks increased from 3088 BTU/ton-mile to 6231 BTU/ton-mile. The primary reason for this is that the load size was cut almost in half along with a reduction in the miles per gallon. No source for the data is provided and the back haul energy is the same 79.3% of the loaded energy, which is again too high a value. Specifically, the DOE reports that the medium-sized trucks (truck classes 3-6) have payload capacity shares between 50% and

FF56-60 continued from above

[1] https://info.ornl.gov/sites/publications/Files/Pub104063.pdf

FF56-61 continued from above

[2] https://www.energy.gov/eere/vehicles/fact-621-may-3-2010-gross-vehicle-weight-vs-empty-vehicle-weight.

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100% of the unloaded weight, which suggests that the back haul energy use should be 50% to 66% of the loaded energy use. FF56-61 cont.

Sugarcane Ethanol Emissions

We made a number of comments on the carbon intensity of the sugarcane pathway, which were not adopted in the 15-day notice. Implementation of these suggestions would have increased the CI of sugarcane ethanol by about 5.5 g/MJ. To ensure the Proposed Amendments are based on the best available scientific information, our suggested changes should be implemented. FF56-62

Summary of 15-day Modifications for EV and HV

In the 15-day notice, ARB proposes to greatly expand the credits for EV and HEV vehicle refueling infrastructure. In the original proposal, credit is given for fuel used by these vehicles. But in the 15-day notice, ARB proposes to give credits to infrastructure built to refill EVs and HEVs based on refueling capacity, rather than fuel use. ARB proposes some limits on the size of these credits in any one-quarter of a year, and also the life of these credits. But such "capacity" credits achieve no GHG emission reductions, like the actual fuel use. FF56-63

The proposal appears to be hurriedly developed, and there is not sufficient time available for the public to comment on the concerns that this raises. It is not clear why ARB did not propose this at an earlier date. Accordingly, additional time for public comment should be permitted.

To the extent ARB continues to propose capacity credits for HEVs and EVs, ARB should provide capacity credits for other low-CI alternative fuels, including E15. Notably, there are no capacity credits for E15 refueling facilities for flexible fuel vehicles (FFVs) under the proposed amendments, which could likewise increase the use of low GHG biofuels.

Curriculum Vitae
For
Thomas Darlington
And
Donald O'Connor

Thomas L. Darlington
President, Air Improvement Resource Inc.

Profile

Thomas L. Darlington is President of Air Improvement Resource, a company formed in 1994 specializing in mobile source emission modeling. He is an internationally recognized expert in mobile source emissions modeling, lifecycle analysis, and land use modeling.

Professional Experience

1994-Present	President, Air Improvement Resource
1993-1994	Director, Mobile Source Programs, Systems Application International
1989-1994	Senior Engineer, General Motors Corporation, Environmental Activities
1988-1989	Senior Project Engineer, Detroit Diesel Corporation
1979-1988	Project Manager, U.S. EPA, Ann Arbor, Michigan

Recent Major Projects

- Provided numerous OMEGA outputs to The Alliance for their review of the 2022-2025 GHG standards
- Participating on behalf of Growth Energy in EPA's MOVES model development stakeholder meetings
- Creating a new California emissions model for offroad equipment
- Published a Society of Automotive Engineers paper at SAE World Congress in 2017 (April 2017) on modeling GHG emission reductions with a high octane, low carbon biofuel (Minnesota Corn Growers and others)
- Published an SAE paper at the 2016 World Congress on our review of EPA's EPAct fuels testing and modeling (Growth Energy)
- Developed Life Cycle reports and complete applications for 8 plants for the California Low Carbon Fuel Standard
- Participated in and provided written comments on California's three 2014 Indirect Land Use (iLUC) workshops (Growth Energy)
- With Purdue University, conducted study of iLUC emissions of rapeseed and other oilseeds in 2013 utilizing an updated version of GTAP (European Biodiesel Board)
- Reviewed EPA's palm oil iLUC emissions in 2013 (NESTE)
- Submitted comments on ARB's new GREET2.0 model
- Reviewed CARB's land use emissions for soybean biodiesel
- Reviewed the land use impacts of the RFS2 from EPA, including the notice of Proposed Rule, Regulatory Impact Analysis, and approximately one hundred documents in the rulemaking docket.

Air Improvement Resource, Inc. 10820 Boyce Rd, Chelsea, Michigan 48118
Phone: 248-921-5096

- Completed a land use study for Renewable Fuels Association and reviewed California Air Resource Board's Initial Statement of Reasons for the Low Carbon Fuel Standard
- Represented three stakeholders in the recent development of the ARB Predictive Model for reformulated gasoline in California (Alliance of Automobile Manufacturers, Renewable Fuels Association and Western States Petroleum Association)
- Represented two stakeholders in EPA's development of the MOVES on-highway emissions model (Alliance of Automobile Manufacturers and Engine Manufacturers Association)
- Developed the effects of ethanol permeation on on-highway and off-highway mobile sources in California and other states for the American Petroleum Institute
- Studied gasoline and diesel fuel options for Southeast Michigan (for SEMCOG, API and Alliance of Automobile Manufacturers)

Recent Publications

Darlington, T., Herwick, G., Kahlbaum, D., and Drake, D., "Modeling the Impact of Reducing Vehicle Greenhouse Gas Emissions with High Compression Engines and High Octane Low Carbon Fuels," SAE 2017-01-0906, 2017, doi: 10.4271/2017-01-0906.

Darlington, T., Kahlbaum, D., Van Hulzen, S., and Furey, R., "Analysis of EPAct Emission Data Using T70 as an Additional Predictor of PM Emissions from Tier 2 Gasoline Vehicles", SAE Technical Paper 2016-01-0996, 2016, doi: 10.4271/2016-01-0996.

"Study of Transportation Fuel Life Cycle Analysis: Review of Economic Models Used to Assess Land Use Effects", CRC-E-88-3, July 2014.

"Land Use Change Greenhouse Gas Emissions of European Biofuel Policies Utilizing the Global Trade Analysis Project Model", Darlington, Kahlbaum, O'Connor, and Mueller, August 30, 2013.

"A Comparison of Corn Ethanol Lifecycle Analyses: California Low Carbon Fuels Standard (LCFS) Versus Renewable Fuels Standard (RFS2)", June 14, 2010. Renewable Fuels Association and Nebraska Corn Board. This study compared and contrasted the corn ethanol lifecycle analyses performed by both CARB (as a part of the LCFS) and the EPA (as a part of RFS2).

"Review of EPA's RFS2 Lifecycle Emissions Analysis for Corn Ethanol", September 25, 2009. Conducted for Renewable Fuels Association. This study reviewed EPA's land use GHG emissions assessment for corn ethanol, including the FASOM and FAPRI models and Winrock land-use types converted and emission factors by ecosystem type. The study made many recommendations for improving the land-use and emissions modeling.

Air Improvement Resource, Inc. 10820 Boyce Rd, Chelsea, Michigan 48118
Phone: 248-921-5096

"Review of CARB's Low Carbon Fuel Standard Proposal", April 15, 2009. Conducted for Renewable Fuels Association. This study reviewed CARB's analysis of land use emissions using GTAP6 and CARB's overall lifecycle emissions for corn ethanol. This study made many recommendations for improving the land use and lifecycle emissions of corn ethanol.

"Emission Benefits of a National Clean Gasoline", August 2008. Conducted for the Alliance of Automobile Manufacturers. This study evaluated the nationwide criteria pollutant emission reductions of a national clean gasoline standard.

"Land Use Effects of Corn-Based Ethanol", February 25, 2009. Conducted for Renewable Fuels Association. This study evaluates possible land use changes and GHG emissions associated with these land use changes as a result of the renewable fuel standard mandated 15 billion gallons of corn ethanol required by calendar year 2015. The study utilized projections of land use in the US and rest of world performed by Informa Economics, LLC, as well as newer estimates of the land use credits of co-products produced by ethanol plants to evaluate possible land use changes.

"On-Road NOx Emission Rates From 1994-2003 Heavy-Duty Trucks", SAE2008-01-1299, conducted for the Engine Manufacturers Association. This study examined manufacturers consent decree emissions data to determine on-road NOx emission rates, and deterioration in emissions from heavy-duty vehicles. (Peer reviewed publication)

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act - Part 2: CO2 and GHG Impacts", SAE2008-01-1853, conducted for the Alliance of Automobile Manufacturers. This paper evaluated the comparison of greenhouse gases from cars and light trucks in the US under both the Federal and California GHG policies. (Peer reviewed publication)

"Effectiveness of the California Light Duty Vehicle Regulations as Compared to Federal Regulations", June 15, 2007. Conducted with NERA Economic Consulting and Sierra Research for The Alliance of Automobile Manufacturers. This study compares the emission benefits of the California and Federal light duty vehicle regulations for HC, CO, NOx, PM, SOx, and Toxics taking into account the difference in emission standards, new vehicle costs and its effect on fleet turnover, new vehicle fuel economy and its effect on vehicle miles traveled, and other factors. Both the EPA MOBILE6 and ARB EMFAC on-road emissions models were used to estimate changes in emissions inventories.

"The Case for a Dual Tech 4 Model Within the California Predictive Model", May 20, 2007. Conducted with ICF International and Transportation Fuels Consulting for the Renewable Fuels Association (RFA). This study developed separate emissions vs fuel property models for lower and higher Tech 4 (1986-1995) vehicles, and showed that utilizing this alternative Predictive Model would result in a higher compliance margin for fuels containing higher volumes of ethanol. It was thought that this could lead to higher ethanol concentrations in the state, but even if the dual model is not used, it is a better representation of the 2015 inventory than the ARB single model.

Air Improvement Resource, Inc. 10820 Boyce Rd, Chelsea, Michigan 48118
Phone: 248-921-5096

"Updated Final Report, Effects of Gasoline Ethanol Blends on Permeation Emissions Contribution to VOC Inventory From On-Road and Off-Road Sources, Inclusion of E-65 Phase 3 Data and Other Updates", June 20, 2007. Conducted for the American Petroleum Institute. This report updates the earlier March 3, 2005 report for API utilizing data collected by CRC and others since of the time of the earlier report.

Final Report, Development of Technical Information for a Regional Fuels Strategy, February 28, 2006. Conducted for the Lake Air Directors Consortium (LADCO). This report provided guidance to the LADCO states (Midwestern states) concerning how to model different types of fuel control programs (in particular) using EPA mobile source models, and how to set up the baseline input files so that results are consistent between the different states.

"Emission Reductions from Changes to Gasoline and Diesel Specifications and Diesel Engine Retrofits in the Southeast Michigan Area", February 23, 2005. Conducted for the Southeast Michigan Council of Governments (SEMCOG), the Alliance of Automobile Manufacturers, and the American Petroleum Institute. This study examined the on-road and off-road emission benefits of many different possible gasoline and diesel fuel specifications that the state could adopt to help meet the 8-hour ozone standards. This study formed the basis for the state's move to lower RVP summer gasoline.

"Examination of Temperature and RVP Effects on CO Emissions in EPA's Certification Database, Final Report", CRC Project No. E-74a, April 11, 2005. Conducted for the Coordinating Research Council. This study compared CO vs temperature results from the MOBILE6 model to the certification data, and recommended further testing, which is being conducted by the CRC at this time.

"Effects of Gasoline Ethanol Blends on Permeation Emissions Contribution to VOC Inventory From On-Road and Off-Road Sources" March 3, 2005. Conducted for the American Petroleum Institute (API). Using data from the CRC-E-65 program, and data collected by the California EPA and Federal EPA, this study estimated the impacts of ethanol use on increasing permeation VOC emissions from on-road vehicles, off-road equipment and vehicles, and from portable containers. Emission inventory estimates were made for a number of geographical areas including the state of California, and results showed that the permeation effect increases anthropogenic VOC inventories by 2-4%.

Review of EPA Report "A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions", February 11, 2003. Conducted for the American Petroleum Institute. This study critically examined the methods that EPA used to develop the impacts of biodiesel fuels on HC, CO, NOx, and PM emissions.

"Well-To Wheels Analysis of Advanced Fuel/Vehicle Systems – A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions", May 2005. Conducted for General Motors Corporation, with Argonne National Labs. This study examined many different well to wheels pathways for various fuels, and their impacts on GHG and criteria pollutant emissions.

Air Improvement Resource, Inc. 10820 Boyce Rd, Chelsea, Michigan 48118
Phone: 248-921-5096

"Potential Delaware Air Emission Impacts of Switching From MTBE to Ethanol in the Reformulated Gasoline Program", May 26, 2005. Conducted for Lyondell Chemical Company. This study examined the HC, CO, and NOx impacts of switching from MTBE to ethanol.

"Potential Massachusetts Air Emission Impacts of Switching From MTBE to Ethanol in the Reformulated Gasoline Program" June 17, 2005. Conducted for Lyondell Chemical Company. This study is similar to the Delaware study above.

"Potential Maryland Air Emission Impacts of a Ban on MTBE in the Reformulated Gasoline Program", October 18, 2005. Conducted for Lyondell Chemical Company. This study is similar to the Delaware study above.

"MOBILE6.2C with Ethanol Permeation and Ethanol NOx Effects", February 8, 2005. Conducted for Health Canada. This study modified the MOBILE6.2C model for ethanol permeation VOC and ethanol NOx effects.

Education

B. Sc., (Materials and Metallurgical Engineering), University of Michigan, Ann Arbor, 1979
Post Graduate Courses (Business Administration), University of Michigan, Ann Arbor, 1982

Donald Victor O'Connor, P. Eng.

Summary

An innovative, achievement oriented business leader with over 40 years experience with energy and environmental issues in Canada. Successfully developed and commercialized environmentally sound energy alternatives.
Background includes:

- Development of the GHGenius life cycle assessment model for energy systems.
- Developing Canada's largest alternative fuel retailing program.
- Establishment of the ethanol industry in Western Canada, from manufacturing to retailing. Extensive experience with production of biofuels.
- Detailed knowledge of fuels and the fuels industry. Technical expertise regarding the utilization of methanol, ethanol, natural gas, propane, hydrogen, gasoline and diesel fuels.
- Developing objectives, strategy and tactics in highly competitive manufacturing and retail industries.

Professional Experience

(S&T)^2 Consultants Inc. (1998-2018)

President

The firm specializes in energy and environment issues. (S&T)^2 helps corporations with business development strategies concerning new energy markets and products and it helps governments understand the business, energy and environmental issues of new energy pathways.
Mr. O'Connor has recently provided strategic advice on fuels, transportation issues, and greenhouse gas emissions to a number of Provincial governments, several Canadian Federal Government departments, and international agencies and governments. Mr. O'Connor has also consulted for a number of companies developing new technologies for alternative fuelled vehicles and companies developing new transportation fuel processes and facilities.

Projects have included:

- Development of the GHGenius life cycle assessment model
- Development of the Ontario Ethanol Growth Fund. Led to the establishment of 50% of the Canadian ethanol production capacity.
- Analysis of the US EPA RFS program for the National Biodiesel Board. Resulted in soybean biodiesel passing the GHG emission threshold established by the US Congress.
- Establishment of the qualifying criteria for biofuels under the Alberta RFS program.
- Proposed and participated in the development of a novel, patented process for the production of ethanol from woody lignocellulosic feedstock. Five patents granted.
- Provided guidance and recommendations for the establishment of a biofuels program for the Government of Peru.
- Provided project development services for the development and construction of western Canada's largest fuel ethanol plant.

Mohawk Canada Limited (1981 – 1998)

Mohawk was Western Canada's largest independent automotive fuel retailer offering environmentally responsible fuels and lubricants through 300 retail and bulk facilities. Mohawk also manufactures re-refined lubricants from used oil, and ethanol, distillers' grains and Fibrotein from grain.

President, COO, and Director, Mohawk Products Ltd. (1997 – 1998)
President, COO, and Director, Mohawk Lubricants Ltd. (1992 – 1998)
Vice President, Supply and Manufacturing (1989 – 1998)
Various positions in R&D, manufacturing and supply (1981-1989)

Donald Victor O'Connor, P. Eng.

Responsibilities:

- Led and managed three business units simultaneously. These units manufactured lubricants from used oil, processed grain into ethanol and human and animal foods, and the corporate supply function covering all aspects of fuels' development, supply and distribution, and core supplier relationships for convenience goods and corporate services. Recommended objectives, strategy and tactics consistent with the organization's values to achieve corporate vision.

Accomplishments:

- Contributed to the development of a vision and unique corporate positioning that allowed the company to increase its market share by 50% over five years;
- Initiated and led the successful introduction of several new or differentiated alternative fuels to the market (Natural Gas, M85, Ethanol blends (Regular Plus and Premium Plus), and premium diesel fuels (Diesel with ECA and Diesel Max);
- Led the turnaround of used oil re-refining business by doubling production and sales over a four-year period. Increased bottom line by 500% and made the operation the most profitable of its kind in the world.
- Introduced a strategic sourcing program throughout the organization.

Additional Professional Activities

- Advisory Committee. ILUC Quantification Study of EU Biofuels. GLOBIOM Model ILUC project.
- Canadian expert on GHG emissions and indirect effects to ISO TC 248 developing ISO 13065.
- Expert Working Group on Indirect Effects. California Air Resources Board. 2010
- Canadian Biomass Innovation Network. External Advisory Panel. 2005-2010.
- Director, B.C. Buildings Corporation. 2000-2002
- Co-Chair 1999-2001. Member, Executive Committee on Cleaner Technology Vehicles (Minister's Committee, B.C. Environment) (1995 - 2001)
- Director, Pound-Maker Adventures (1990 - 1998) An integrated ethanol plant cattle feeding operation in Saskatchewan.
- Director, Canadian Renewable Fuels Association (1990 – 1998, 2000-2002)
- Member, Environment Advisory Committee, Vancouver Foundation (2001-2003)
- Member, Ethanol BC Board (2000-2010)
- Member, Bio-based Products R&D Advisory Council, BIOCAP Canada, (2002-2003)
- Member, National Advisory Committee on Bioenergy (1984 - 1990)
- Member, Efficiency and Alternative Energy Committee, Minister's National Advisory Council to CANMET (1990 - 1994)
- Chair, Ethanol Program Advisory Committee, Agriculture and Agrifood Canada (1992 - 1997)
- Canadian Petroleum Products Institute, Western Division Management Committee (1996 - 1998)
- Numerous presentations on alternative fuels at National and International conferences.

Employment

- Manager, Energy and Environmental Technology, B.H. Levelton & Associates Ltd. Consulting Engineers (1974 - 1981)
- Air Engineer, Province of British Columbia, Pollution Control Branch (1973 - 1974)

Patents

- Mazza; Giuseppe, Gao; Lei, Oomah; B. Dave, O'Connor; Donald, Crowe; Brian. "Functional, water-soluble protein-fibre products from grains". 07/19/2001. U.S. Patent No. 6,261,629.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennestad; Gordon, Berlin; Alex, MacLachlan; John Ross. "Continuous counter-current organosolv processing of lignocellulosic feedstocks," 12/16/08, U.S. Patent No. 7,465,791.
- Berlin; Alex, Pye; Edward Kendall, O'Connor; Donald, "Concurrent saccharification and fermentation of fibrous biomass," 11/15/11, U.S. Patent No. 8,058,041.

- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma; Raymond. Continuous counter-current organosolv processing of lignocellulosic feedstocks. 6/05/12, U.S. Patent No. 8,193,324.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma. Continuous counter-current organosolv processing of lignocellulosic feedstocks. 7/24/12, U.S. Patent No. 8,227,004.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma. Modular system for organosolv fractionation of lignocellulosic feedstock. 10/09/2013. U.S. Patent 8,528,463.
- Hallberg; Christer, O'Connor; Donald, Rushton; Michael, Pye; Edward Kendall, Gjennstad; Gordon, Berlin; Alex, MacLachlan; John Ross, Ma. Continuous counter-current organosolv processing of lignocellulosic feedstocks. US Patent 8,772,427.

Peer Reviewed Papers

- Vuksan, V., Jenkins, D. J., Vidgen, E., Ransom, T. P., Ng, M. K., Culhane, C. T., & O'Connor, D. 1999. A novel source of wheat fiber and protein: effects on fecal bulk and serum lipids–. The American journal of clinical nutrition, 69(2), 226-230.
- O'Connor, D., Esteghlalian, A.R., Gregg, D.J. and Saddler, J.N. 2003. Carbon Balance of Ethanol from Wood: The effect of Feedstock Source in Canada. The Role of Boreal Forests and Forestry in the Global Carbon Budget. pp. 289-296 (Proceedings of the International Science Conference, Edm. Alta. May 2000).
- Hünerberg, M., Little, S.M., Beauchemin, K.A., McGinn, S.M., O'Connor, D., Okine, E.K., Harstad, O.M., Kröbel, R. and McAllister, T.A., 2014. Feeding high concentrations of corn dried distillers' grains decreases methane, but increases nitrous oxide emissions from beef cattle production. *Agricultural Systems*, *127*, pp.19-27.
- Chen, R., Qin, Z., Han, J., Wang, M., Taheripour, F., Tyner, W., O'Connor, D. and Duffield, J., 2018. Life cycle energy and greenhouse gas emission effects of biodiesel in the United States with induced land use change impacts. *Bioresource technology*, *251*, pp.249-258.

Education

- Bachelor of Applied Science, Mechanical Engineering, University of British Columbia (1973)

Professional Memberships

- Association of Professional Engineers and Geoscientists of British Columbia
- Association of Professional Engineers of Ontario
- Society of Automotive Engineers

Awards

- Canadian Renewable Fuels Association. Outstanding Dedication to the Advancement of Renewable Fuels in Canada. 2007.

Exhibit "B"

Comments on Notice of Public Availability of Modified Text and Availability of Additional Documents and Information Dated June 20, 2018

Prepared by Jim Lyons, Trinity Consultants
July 5, 2018

CARB's Proposal to Provide "Capacity" Credits for Electric and Fuel Cell Vehicle Infrastructure is Inappropriate and Should Be Eliminated

As part of the 15-day notice, CARB proposes to add a new section, 95486.2 to Title 17, California Code of Regulations. The sole purpose of this section is to provide LCFS credits to hydrogen stations and direct current (DC) fast charging stations for the difference in the installed capacity to deliver hydrogen and electricity in addition to the LCFS credits provided for the "fuel" that is actually delivered to and used by vehicles. In more simple terms, what CARB is proposing is to provide LCFS credits to the owners of hydrogen and DC fast charging stations for taking actions that, in and of themselves, do not result in any actual reduction in greenhouse gas (GHG) emissions or in the carbon intensity (CI) of transportation fuels sold in California. Further, CARB staff is proposing to award these LCFS credits that do not result in any reduction in GHG emissions or CI at levels of up to or perhaps slightly beyond 5%[1] of the GHG emissions associated with the use of deficit generating fuels including conventional gasoline and diesel fuel. As is stated on pages 6 and 7 of Appendix F to the 15-day notice, the purpose of these "capacity" credits for hydrogen and DC fast charging stations is not to reduce actual GHG emissions or lowering the CI level of California transportation fuels, but rather "to support the expansions of such infrastructure as directed by Governor's Executive Order B-48-18." It is inappropriate for CARB to allow what are essentially LCFS credits based on the imagined but unverified use of electricity and hydrogen as transportation fuels that will result in no verifiable environmental benefits and which will effectively decrease the actual GHG reductions associated with the LCFS program by up to 5% depending on the year in question and the degree to which applicants request capacity credits. FF56-64

Further, CARB has not provided any quantification regarding the magnitude of the potential GHG reductions that could be lost through the capacity credits. The question of the potential magnitude of these lost reductions can be easily addressed using CARB's Illustrative Compliance Scenario.[2] Assuming for purposes of illustration that capacity credits equal to 5% of deficits are distributed in calendar year 2020 and using the other assumptions of CARB's "LD/High ZEV/20%", the potential lost benefits for calendar year

[1] More specifically, up to or slightly more than 2.5% would be allowed for both hydrogen and DC fast charging stations for a total of up to or slightly more than 5% if both options are fully subscribed.
[2] Available at https://www.arb.ca.gov/fuels/lcfs/rulemakingdocs.htm

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2020 alone to amount to approximately 820,000 metric tons of GHG emissions[3] which at an LCFS credit price of $100 per metric ton translates into a transfer of roughly $82,000,000 to owners of hydrogen and DC fast charging stations – again just during calendar year 2020. The potential cumulative value of the transfer of money to owners of hydrogen and DC fast charging stations given the parameters of CARB's proposed "capacity" credit provisions is clearly much larger than $82 million.

It should also be noted that the generation of LCFS credits from actions that do not result in direct reductions in GHG emissions through the proposed "capacity" provisions, will decrease the value of LCFS credits generated by other means that do in fact result in actual reductions in GHG emissions. In order to see that this is the case, one only has to recognize that the "capacity" credit provisions will artificially increase the supply of LCFS credits for which there is a finite demand which in turn will decrease the value of all LCFS credits.

FF56-64 continues to footnote below

In addition to proposing these capacity credits which do not result in any verifiable environmental benefit, CARB has not performed any analysis of the degree to which they will increase the number of hydrogen and DC fast charging stations that are constructed in California and has failed to update the draft Environmental Analysis (EA) to consider those impacts, to date. The construction or modification of new facility will plainly lead to potentially significant environmental effects. This conclusion is recognized, for example, in Table 1-1 of the draft EA, which indicates that the construction or modification of various facilities can lead to "potentially significant and unavoidable" adverse environmental impacts related to:

FF56-65

- Aesthetics;
- Air Quality;
- Biological Resources;
- Cultural Resources;
- Geology and Soil;
- Hydrologic Resources;
- Noise; and
- Traffic and Transportation.

With respect to air quality, the Draft EA provides the following assessment of the impacts that will results from construction of new facilities including hydrogen and DC fast charging stations:

> *Generally, it is expected that during the construction phase for any facilities, criteria air pollutants and toxic air contaminants (TACs) could be generated from a variety of activities and emission sources. These emissions would be temporary and occur intermittently depending on the intensity of construction on a given day. Site grading and excavation activities would*

[3] Gasoline deficits for 2020 under this scenario 13.6 million metric tons and diesel deficits are 2.79 million metric tons.

FF56-64 continued from above

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> *generate fugitive particulate matter (PM) dust emissions, which is the primary pollutant of concern during construction. Fugitive PM dust emissions (e.g., respirable particulate matter [PM10] and fine particulate matter [PM2.5]) vary as a function of several parameters, such as soil silt content and moisture, wind speed, acreage of disturbance area, and the intensity of activity performed with construction equipment. Exhaust emissions from off-road construction equipment, material delivery trips, and construction worker-commute trips could also contribute to short-term increases in PM emissions, but to a lesser extent. Exhaust emissions from construction-related mobile sources could also result in short-term increases in CO, CO2, hydrocarbons, PM, reactive organic gases (ROG), and nitrogen oxides (NOx). These emission types and associated levels fluctuate greatly depending on the particular type, number, and duration of usage for the varying equipment.*

Further, CARB provides no assessment of how those impacts could or should be mitigated.

FF56-65 cont.

Just as the EA has not been revised to address the environmental impacts of "capacity" credit provisions, the economic analysis presented in the ISOR has not been modified to account for the decreases in LCFS credit prices resulting from capacity credits and the associated economic impacts on low CI fuel producers.

FF56-66a

As noted above, the potential magnitude of the value of capacity credits could be on the order of tens of millions of dollars per year. Despite this, there is no evidence in the 15-Day Notice justifying the need for creating LCFS credits that provide no reductions in GHG emissions for incentivizing construction of hydrogen and DC fast charging stations. The failure to justify the need for capacity credits is particularly disconcerting in light of the fact that the California Energy Commission (CEC) has spent, and continues to spend, millions of dollars to subsidize hydrogen station construction[4] as well as the deployment of DC fast charging stations and other electric vehicle infrastructure.[5] Given this, the appropriate mechanism for increasing the number of hydrogen and DC fast charging stations is to continue to provide grant funding through the CEC's ARFVT program[6] not paying owners of hydrogen and DC fast charging stations through the issuance of LCFS credits that provide no verifiable reductions in GHG emissions. However, in the event that CARB does provide capacity credits, then the agency should provide similar "capacity" credits for all types of low CI biofuel infrastructure including E85 refueling facilities.

FF56-66b continues to footnotes below

Given that CARB is proposing a completely new regulatory element in a 15-day notice[7], it should also be noted that there are alternatives that CARB has failed to consider that would

FF56-66c continues to footnote below and next page

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[4] See http://www.energy.ca.gov/2017publications/CEC-600-2017-011/CEC-600-2017-011.pdf
[5] See http://www.energy.ca.gov/transportation/tour/ev_infrastructure/
[6] See http://www.energy.ca.gov/altfuels/

FF56-66b continued from above

[7] CARB refers to "capacity" credits as "unprecedented and novel" and they are discussed nowhere in the Initial Statement of Reasons for the proposed LCFS amendments.

FF56-66c continued from above

3

generate substantial additional amounts of LCFS credits tied to real reductions in GHG emissions and the CI of California transportation fuels. One such alternative would be to allow the sale of E15 in California. Again it is easy to assess the potential GHG reduction benefits from allowing E15 to be sold in California. Using the same example provided above, e.g. CARB's LD/High ZEV/20% scenario for calendar year 2020, and assuming that the credits generated only by starch ethanol increase by 50% (given that the volume of ethanol used will increase by 50% going from E10 to E15), the resulting reduction in GHG emissions would equal 1,126,000 metric tons of GHG emissions from increased use of ethanol plus a further reduction of another 760,000 metric tons of GHG emissions due to reduce use of petroleum based gasoline blendstocks. Again, it is completely unclear why CARB is forgoing the opportunity to generate significant reductions in GHG emissions through allowing the use of E15 while at the same time providing large amounts of LCFS credits to hydrogen and DC fast charging station operators that do not involve a reduction in GHG emissions. Nor has CARB articulated any environmental basis for making these edits in its 15-Day Notice. FF56-66c cont.

CARB's New Proposal for Separate "Sunset" Dates for Biodiesel Mitigation Requirements under the Alternative Diesel Fuel (ADF) Regulation May Lead to Increases in NOx Emissions that Are Not Accounted for in the EA

One element of the CARB staff proposal as documented in the Initial Statement of Reasons[8] was an extension of the sunset date for the biodiesel NOx mitigation requirements of the ADF regulation found in section 2293.6, Title 17 California Code of Regulations until such time that at least 90% of the hours of operation of diesel fueled non-road engines in the state were accumulated by so called "new technology diesel engines" (NTDEs) which CARB claims erroneously (as documented in detail in Growth Energy's comments on the staff's original proposal) do not experience increases in NOx emissions from the use of biodiesel.

In the 15-day notice, CARB modifies its original proposal to provide for separate sunset dates for the biodiesel NOx mitigation requirements for on-road and non-road diesel vehicles and engines. In addition, Attachment F to the 15-day notice indicates that this change will likely eliminate mitigation requirements for on-road diesel vehicles by calendar year 2023 and for non-road vehicles and engines by 2030. CARB's original proposal would have left the NOx mitigation requirements in place for all biodiesel sold in California until 2030. Despite this major change to the NOx mitigation requirements proposed in the 15-day notice, CARB has provided no analysis of the potential of this change to increase NOx emissions nor any modifications to the draft EA or other regulatory documents (in particular Appendix G to the ISOR) that allows one to determine the potential significance of the change with respect to adverse environmental impacts or even to discern the relative increases in NOx emissions that CARB staff has estimated to result from the use of biodiesel in on-road and non-road vehicles and engines. FF56-67

[8] See page III-172 of the ISOR for example.

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Despite CARB's failure to analyze the environmental impacts of the proposed change in the NOx mitigation sunset date, it is clear that the change has the potential to increase NOx emissions. First, as noted above, CARB's assumption that there is no increase in NOx emissions from NTDEs is not supported by the available data as documented in detail in Growth Energy's previous comments on the proposed LCFS regulation. Therefore, the shortening of the end of the mitigation period for on-road diesel vehicles from 2030 to 2023 will result in increases in NOx emissions from these vehicles during calendar years 2023 to 2029.

Second, CARB has not proposed any mechanism by which non-mitigated on-road diesel fuel containing biodiesel will be prohibited from introduction into non-road vehicles or engines that do not meet CARB's NTDE definition – a circumstance under which even CARB agrees there would be increases in NOx emissions. For example, the reporting requirements of the ADF regulation do not make any distinction between bio-diesel blends intended for use as on-highway or non-road fuels and there is no explicit prohibition or enforcement mechanism in the ADF regulation against introducing non-mitigated on-highway diesel fuel into any non-road engine. Although dyed non-road diesel fuel is exempt from some state taxes, and is currently less expensive than on-road diesel fuel, some fleets that operate both on- and non-road diesel vehicles and engines may elect to use on-road in all of their vehicles to avoid the need for separate storage and dispensing infrastructure leading to use of non-mitigated biodiesel blends in non-road engines. FF56-67 cont.

Given the above, if CARB truly seeks to impose separate sunset dates, substantial additional modifications to the ADF regulation are required to explicitly protect against the use of non-mitigated on-road fuel in non-road vehicles and engines.

Curriculum Vitae

For

Jim Lyons

James Lyons

***Principal Consultant* – Sacramento Office**

Trinity Consultants

AREAS OF SPECIALIZATION

- New Vehicle and Engine Certification
- Development and Assessment of Mobile Source Emission Control Strategies
- Development and Assessment of Strategies for Reduction of Criteria Pollutant and GHG Emissions Related to Transportation Fuels – Including Alternative Fuels and Fuel Additives
- Design and Implementation of Vehicle Testing Programs and Data Analysis
- Enforcement and Litigation Support Related to Mobile Sources and Transportation Fuels
- Intellectual Property Disputes Involving Engine and Emission Control System Design, Function, and Novelty
- Tracking and Reporting of California Air Resources Board Activities Related to the Regulation of Mobile Source Emissions and Transportation Fuels
- Emission Inventories and Quantification

EDUCATION

M.S., Chemical Engineering, University of California, Los Angeles

B.S., Cum Laude, Chemistry, University of California, Irving

AFFILIATIONS

Society of Automotive Engineers

American Chemical Society

SUMMARY OF EXPERIENCE

A Principal Consultant and head of Trinity's Mobile Source and Fuels team, Mr. Lyons has extensive experience related to fuels issues and emissions, including the emission impacts of changes in gasoline and diesel fuel composition and substitution of alternative fuels for petroleum-based fuels. Specific projects have required work on issues related to the emissions impacts of changes in gasoline and diesel fuel as well as compliance with California Air Resources Board (CARB) and U.S. EPA regulations related to gasoline and diesel fuel properties and specifications, assessment of costs and benefits of alternative fuels and alternatively fueled vehicles, and direct involvement in analyses of issues related to CARB and EPA fuels regulations, including the Renewable Fuel Standards (RFS) and Low Carbon Fuel Standards. He has also provided expert services in fuels-related litigations.

Additional responsibilities include oversight and execution of complex analyses of the emission benefits, costs, and cost-effectiveness of mobile source air pollution control measures. Mr. Lyons has developed particular expertise with respect to the assessment of control measures involving accelerated vehicle/engine retirement programs; the deployment of advanced emission control systems, including electric fuel cell and hybrid technologies for on- and non-road gasoline- and diesel-powered vehicles and engines, as well as on-vehicle evaporative and refueling emission control systems. Other duties include assessments of the activities of federal, state, and local regulatory agencies with respect to motor vehicle emissions and reports to clients regarding those activities. Mr. Lyons has extensive litigation experience related to air quality and fuels including gasoline property and renewable fuels regulations, product liability, and intellectual property issues.

TECHNICAL EXPERTISE

Fuels Regulations. Managed numerous projects related to assessments of Low Carbon Fuel Standard (LCFS) regulations adopted or being prepared by California and a number of other jurisdictions. Has also been involved in the review of reformulated gasoline and diesel fuel regulations, including the federal RFS 1, RFS 2, and Tier 3 regulations.

Mobile Source Emissions Control. Participated in the design and evaluation of mobile source emission control measures and emission control systems; development of mobile source emissions modeling software; development of mobile source emission inventories; design and management of supporting field and laboratory studies; and the design and evaluation of vehicle emissions inspection and maintenance programs. Mobile source categories include on- and off-road vehicles, locomotives, marine vessels, and aircraft. Directly involved in assessing changes in vehicle technology required to comply with federal, California, and Mexican new-vehicle greenhouse gas and fuel economy standards for light-duty vehicles.

New Vehicle and Engine Certification. Directly participated in and managed efforts related to obtaining U.S. EPA and California Air Resources Board certification for new engines and vehicles, including activities related to agency enforcement actions and on-going compliance requirements.

Air Quality Planning and Strategy Development. Has been involved in the development and critical assessment of mobile source and transportation fuels elements of State Implementation Plans.

Emission Control System Design and Evaluation. Provided support for the design and assessment of alternative emission control techniques, and for troubleshooting control system issues. Issues assessed have include VOC, CO, NOx, SOx, and PM control systems in various applications.

Expert Witness Services. Presented testimony and served as an expert or consulting expert on numerous cases in federal and state courts involving issues related to government regulations affecting mobile source certifications, in-use emissions issues, fuel regulations, intellectual property issues related to emission controls and fuels, and product liability.

EMPLOYMENT HISTORY

2014 – Present Trinity Consultants
1991 – 2014 Sierra Research
1985 – 1991 California Air Resources Board

SELECTED PUBLICATIONS (AUTHOR OR CO-AUTHOR)

"Follow-On Study of Transportation Fuel Life Cycle Analysis: Review of Current CARB and EPA Estimates of Land Use Change (LUC) Impacts," Sierra Research Report No. SR2016-08-01, prepared for the Coordinating Research Council, CRC Project No. E-88-3b, August 2016.

"Review of EPA's MOVES2014 Model," Sierra Research Report No. SR2016-07-01, prepared for the Coordinating Research Council, CRC Project No. E-101, July 2016.

"Development of Vehicle Attribute Forecasts for the '2015 Integrated Energy Policy Report,'" prepared for the California Energy Commission, February 5, 2016.

"Sensitivity Analysis of Key Assumptions on Energy and Environmental Economics (E3) 'California Pathways GHG Scenario Results' as They Pertain to the Light-Duty Vehicle Sector," prepared for the Alliance of Automobile Manufacturers, October 2015.

"Review of Energy and Environmental Economics (E3) "California Pathways GHG Scenario Results" as They Pertain to the Light-Duty Vehicle Sector," prepared for the Alliance of Automobile Manufacturers, October 2015.

"International Light-Duty Vehicle Fuel Economy and Greenhouse Gas Standards Analysis," prepared for the Alliance of Automobile Manufacturers, July 2015.

James Lyons
Principal Consultant – Sacramento Office

Trinity Consultants

"Quantifying Aircraft Lead Emissions at Airports," prepared for the Transportation Research Board, Airport Cooperative Research Program, October 2014.

"Best Practices Guidebook for Preparing Lead (Pb) Emission Inventories from Piston-Powered Aircraft," prepared for the Transportation Research Board, Airport Cooperative Research Program, October 2014.

"Development of Vehicle Attribute Forecasts for 2013 IEPR," Sierra Research Report No. SR2014-01-01, prepared for the California Energy Commission, January 2014.

"Assessment of the Emission Benefits of U.S. EPA's Proposed Tier 3 Motor Vehicle Emission and Fuel Standards," Sierra Research Report No. SR2013-06-01, prepared for the American Petroleum Institute, June 2013.

"Development of Inventory and Speciation Inputs for Ethanol Blends," Sierra Research Report No. SR2012-05-01, prepared for the Coordinating Research Council, Inc. (CRC), May 2012.

"Review of CARB Staff Analysis of 'Illustrative' Low Carbon Fuel Standard (LCFS) Compliance Scenarios," Sierra Research Report No. SR2012-02-01, prepared for the Western States Petroleum Association, February 20, 2012.

"Review of CARB On-Road Heavy-Duty Diesel Emissions Inventory," Sierra Research Report No. SR2010-11-01, prepared for The Ad Hoc Working Group, November 2010.

"Identification and Review of State/Federal Legislative and Regulatory Changes Required for the Introduction of New Transportation Fuels," Sierra Research Report No. SR2010-08-01, prepared for the American Petroleum Institute, August 2010.

"Technical Review of EPA Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis for Non-GHG Pollutants," Sierra Research Report No. SR2010-05-01, prepared for the American Petroleum Institute, May 2010.

"Effects of Gas Composition on Emissions from Heavy-Duty Natural Gas Engines," Sierra Research Report No. SR2010-02-01, prepared for the Southern California Gas Company, February 2010.

"Effects of Gas Composition on Emissions from a Light-Duty Natural Gas Vehicle," Sierra Research Report No. SR2009-11-01, prepared for the Southern California Gas Company, November 2009.

"Technical Review of 2009 EPA Draft Regulatory Impact Analysis for Non-GHG Pollutants Due to Changes to the Renewable Fuel Standard," Sierra Research Report No. SR2009-09-01, prepared for the American Petroleum Institute, September 2009.

"Effects of Vapor Pressure, Oxygen Content, and Temperature on CO Exhaust Emissions," Sierra Research Report No. 2009-05-03, prepared for the Coordinating Research Council, May 2009.

"Technical Review of 2007 EPA Regulatory Impact Analysis Methodology for the Renewable Fuels Standard," Sierra Research Report No. 2008-09-02, prepared for the American Petroleum Institute, September 2008.

"Impacts of MMT Use in Unleaded Gasoline on Engines, Emission Control Systems, and Emissions," Sierra Research Report No. 2008-08-01, prepared for McMillan Binch Mendelsohn LLP, Canadian Vehicle Manufacturers' Association, and Association of International Automobile Manufacturers of Canada, August 2008.

"Attachment to Comments Regarding the NHTSA Proposal for Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015, Docket No. NHTSA-2008-0089," Sierra Research Report No. SR2008-06-01, prepared for the Alliance of Automobile Manufacturers, June 2008.

"Evaluation of California Greenhouse Gas Standards and Federal Energy Independence and Security Act – Part 1: Impacts on New Vehicle Fuel Economy," SAE Paper No. 2008-01-1852, Society of Automotive Engineers, 2008.

"Basic Analysis of the Cost and Long-Term Impact of the Energy Independence and Security Act Fuel Economy Standards," Sierra Research Report No. SR 2008-04-01, April 2008.

"The Benefits of Reducing Fuel Consumption and Greenhouse Gas Emissions from Light-Duty Vehicles," SAE Paper No. 2008-01-0684, Society of Automotive Engineers, 2008.

"Assessment of the Need for Long-Term Reduction in Consumer Product Emissions in South Coast Air Basin," Sierra Research Report No. 2007-09-03, prepared for the Consumer Specialty Products Association, September 2007.

"Summary of Federal and California Subsidies for Alternative Fuels," Sierra Research Report No. SR2007-04-02, prepared for the Western States Petroleum Association, April 2007.

"Analysis of IRTA Report on Water-Based Automotive Products," Sierra Research Report No. SR2006-08-02, prepared for the Consumer Specialty Projects Association and Automotive Specialty Products Alliance, August 2006.

"Evaluation of Pennsylvania's Implementation of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2006-04-01, prepared for Alliance of Automobile Manufacturers, April 12, 2006.

"Evaluation of New Jersey's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-03, prepared for the Alliance of Automobile Manufacturers, September 30, 2005.

"Evaluation of Vermont's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-09-02, prepared for the Alliance of Automobile Manufacturers, September 19, 2005.

"Assessment of the Cost-Effectiveness of Compliance Strategies for Selected Eight-Hour Ozone NAAQS Nonattainment Areas," Sierra Research Report No. SR2005-08-04, prepared for the American Petroleum Institute, August 30, 2005.

"Evaluation of Connecticut's Adoption of California's Greenhouse Gas Regulations on Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-08-03, prepared for the Alliance of Automobile Manufacturers, August 26, 2005.

James Lyons
Principal Consultant – Sacramento Office

Trinity Consultants

"Evaluation of New York's Adoption of California's Greenhouse Gas Regulations On Criteria Pollutants and Precursor Emissions," Sierra Research Report No. SR2005-07-04, prepared for the Alliance of Automobile Manufacturers, July 14, 2005.

"Review of MOVES2004," Sierra Research Report No. SR2005-07-01, prepared for the Alliance of Automobile Manufacturers, July 11, 2005.

"Review of Mobile Source Air Toxics (MSAT) Emissions from On-Highway Vehicles: Literature Review, Database, Development, and Recommendations for Future Studies," Sierra Research Report No. SR2005-03-01, prepared for the American Petroleum Institute, March 4, 2005.

"The Contribution of Diesel Engines to Emissions of ROG, NOx, and PM2.5 in California: Past, Present, and Future," Sierra Research Report No. SR2005-02-01, prepared for Diesel Technology Forum, February 2005.

"Fuel Effects on Highway Mobile Source Air Toxics (MSAT) Emissions," Sierra Research Report No. SR2004-12-01, prepared for the American Petroleum Institute, December 23, 2004.

"Review of the August 2004 Proposed CARB Regulations to Control Greenhouse Gas Emissions from Motor Vehicles: Cost Effectiveness for the Vehicle Owner or Operator – Appendix C to the Comments of The Alliance of Automobile Manufacturers," Sierra Research Report No. SR2004-09-04, prepared for the Alliance of Automobile Manufacturers, September 2004.

"Emission and Economic Impacts of an Electric Forklift Mandate," Sierra Research Report No. SR2003-12-01, prepared for National Propane Gas Association,
December 12, 2003.

"Reducing California's Energy Dependence," Sierra Research Report No. SR2003-11-03, prepared for Alliance of Automobile Manufacturers, November 25, 2003.

"Evaluation of Fuel Effects on Nonroad Mobile Source Air Toxics (MSAT) Emissions: Literature Review, Database Development, and Recommendations for Future Studies," Sierra Research Report No. SR2003-10-01, prepared for American Petroleum Institute, October 3, 2003.

"Review of Current and Future CO Emissions from On-Road Vehicles in Selected Western Areas," Sierra Research Report No. SR03-01-01, prepared for the Western States Petroleum Association, January 2003.

"Review of CO Compliance Status in Selected Western Areas," Sierra Research Report No. SR02-09-04, prepared for the Western States Petroleum Association, September 2002.

"Impacts Associated With the Use of MMT as an Octane Enhancing Additive in Gasoline – A Critical Review", Sierra Research Report No. SR02-07-01, prepared for Canadian Vehicle Manufacturers Association and Association of International Automobile Manufacturers of Canada, July 24, 2002.

"Critical Review of 'Safety Oversight for Mexico-Domiciled Commercial Motor Carriers, Final Programmatic Environmental Assessment', Prepared by John A Volpe Transportation Systems Center, January 2002," Sierra Research Report No. SR02-04-01, April 16, 2002.

James Lyons
Principal Consultant – Sacramento Office

Trinity Consultants

"Critical Review of the Method Used by the South Coast Air Quality Management District to Establish the Emissions Equivalency of Heavy-Duty Diesel- and Alternatively Fueled Engines", Sierra Research Report No. SR01-12-03, prepared for Western States Petroleum Association, December 21, 2001.

"Review of U.S. EPA's Diesel Fuel Impact Model", Sierra Research Report No. SR01-10-01, prepared for American Trucking Associations, Inc., October 25, 2001.

"Operation of a Pilot Program for Voluntary Accelerated Retirement of Light-Duty Vehicles in the South Coast Air Basin," Sierra Research Report No. SR01-05-02, prepared for California Air Resources Board, May 2001.

"Comparison of Emission Characteristics of Advanced Heavy-Duty Diesel and CNG Engines," Sierra Report No. SR01-05-01, prepared for Western States Petroleum Association, May 2001.

"Analysis of Southwest Research Institute Test Data on Inboard and Sterndrive Marine Engines," Sierra Report No. SR01-01-01, prepared for National Marine Manufacturers Association, January 2001.

"Institutional Support Programs for Alternative Fuels and Alternative Fuel Vehicles in Arizona: 2000 Update," Sierra Report No. SR00-12-04, prepared for Western States Petroleum Association, December 2000.

"Real-Time Evaporative Emissions Measurement: Mid-Morning Commute and Partial Diurnal Events," SAE Paper No. 2000-01-2959, October 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," SAE Paper No. 2000-01-2958, October 2000.

"A Comparative Analysis of the Feasibility and Cost of Compliance with Potential Future Emission Standards for Heavy-Duty Vehicles Using Diesel or Natural Gas," Sierra Research Report No. SR00-02-02, prepared for Californians For a Sound Fuel Strategy, February 2000.

"Critical Review of the Report Entitled 'Economic Impacts of On Board Diagnostic Regulations (OBD II)' Prepared by Spectrum Economics," Sierra Research Report No. SR00-01-02, prepared for the Alliance of Automobile Manufacturers, January 2000.

"Potential Evaporative Emission Impacts Associated with the Introduction of Ethanol-Gasoline Blends in California," Sierra Research Report No. SR00-01-01, prepared for the American Methanol Institute, January 2000.

"Evaporative Emissions from Late-Model In-Use Vehicles," Sierra Research Report No. SR99-10-03, prepared for the Coordinating Research Council, October 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," SAE Paper No. 1999-01-3676, August 1999.

"Future Diesel-Fueled Engine Emission Control Technologies and Their Implications for Diesel Fuel Properties," Sierra Research Report No. SR99-08-01, prepared for the American Petroleum Institute, August 1999.

"Analysis of Compliance Feasibility under Proposed Tier 2 Emission Standards for Passenger Cars and Light Trucks," Sierra Research Report No. SR99-07-02, July 1999.

"Comparison of the Properties of Jet A and Diesel Fuel," Sierra Research Report No. SR99-02-01, prepared for Pillsbury Madison and Sutro, February 1999.

"Investigation of Sulfur Sensitivity and Reversibility in Late-Model Vehicles," Sierra Research Report No. SR98-12-02, prepared for the American Petroleum Institute, December 1998.

"Analysis of New Motor Vehicle Issues in the Canadian Government's Foundation Paper on Climate Change – Transportation Sector," Sierra Research Report No. SR98-12-01, prepared for the Canadian Vehicle Manufacturers Association, December 1998.

"Investigation of the Relative Emission Sensitivities of LEV Vehicles to Gasoline Sulfur Content - Emission Control System Design and Cost Differences," Sierra Research Report No. SR98-06-01, prepared for the American Petroleum Institute, June 1998.

"Costs, Benefits, and Cost-Effectiveness of CARB's Proposed Tier 2 Regulations for Handheld Equipment Engines and a PPEMA Alternative Regulatory Proposal," Sierra Research Report No. SR98-03-03, prepared for the Portable Power Equipment Manufacturers Association, March 1998.

"Analysis of Diesel Fuel Quality Issues in Maricopa County, Arizona," Sierra Research Report No. SR97-12-03, prepared for the Western States Petroleum Association, December 1997.

"Potential Impact of Sulfur in Gasoline on Motor Vehicle Pollution Control and Monitoring Technologies," prepared for Environment Canada, July 1997.

"Analysis of Mid- and Long-Term Ozone Control Measures for Maricopa County," Sierra Research Report No. SR96-09-02, prepared for the Western States Petroleum Association, September 9, 1996.

"Technical and Policy Issues Associated with the Evaluation of Selected Mobile Source Emission Control Measures in Nevada," Sierra Research Report No. SR96-03-01, prepared for the Western States Petroleum Association, March 1996.

"Cost-Effectiveness of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-05, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"Cost of Stage II Vapor Recovery Systems in the Lower Fraser Valley," Sierra Research Report No. SR95-10-04, prepared for the Province of British Columbia Ministry of Environment Lands and Parks and the Greater Vancouver Regional District, October 1995.

"A Comparative Characterization of Gasoline Dispensing Facilities With and Without Vapor Recovery Systems," Sierra Research Report No. SR95-10-01, prepared for the Province of British Columbia Ministry of Environment Lands and Parks, October 1995.

"Potential Air Quality Impacts from Changes in Gasoline Composition in Arizona," Sierra Research Report No. SR95-04-01, prepared for Mobil Corporation, April 1995.

"Vehicle Scrappage: An Alternative to More Stringent New Vehicle Standards in California," Sierra Research Report No. SR95-03-02, prepared for Texaco, Inc., March 1995.

"Evaluation of CARB SIP Mobile Source Measures," Sierra Research Report No. SR94-11-02, prepared for Western States Petroleum Association, November 1994.

"Reformulated Gasoline Study," prepared by Turner, Mason & Company, DRI/McGraw-Hill, Inc., and Sierra Research, Inc., for the New York State Energy Research and Development Authority, Energy Authority Report No. 94-18, October 1994.

"Phase II Feasibility Study: Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley," Sierra Research Report No. SR94-09-02, prepared for the Greater Vancouver Regional District, September 1994.

"Cost-Effectiveness of Mobile Source Emission Controls from Accelerated Scrappage to Zero Emission Vehicles," Paper No. 94-TP53.05, presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, OH, June 1994.

"Investigation of MOBILE5a Emission Factors, Assessment of I/M Program and LEV Program Emission Benefits," Sierra Research Report No. SR94-06-05, prepared for American Petroleum Institute, June 1994.

"Cost-Effectiveness of the California Low Emission Vehicle Standards," SAE Paper No. 940471, 1994.

"Meeting ZEV Emission Limits Without ZEVs," Sierra Research Report No. SR94-05-06, prepared for Western States Petroleum Association, May 1994.

"Evaluating the Benefits of Air Pollution Control - Method Development and Application to Refueling and Evaporative Emissions Control," Sierra Research Report No. SR94-03-01, prepared for the American Automobile Manufacturers Association, March 1994.

"The Cost-Effectiveness of Further Regulating Mobile Source Emissions," Sierra Research Report No. SR94-02-04, prepared for the American Automobile Manufacturers Association, February 1994.

"Searles Valley Air Quality Study (SVAQS) Final Report," Sierra Research Report No. SR94-02-01, prepared for North American Chemical Company, February 1994.

"A Comparative Study of the Effectiveness of Stage II Refueling Controls and Onboard Refueling Vapor Recovery," Sierra Research Report No. SR93-10-01, prepared for the American Automobile Manufacturers Association, October 1993.

"Evaluation of the Impact of the Proposed Pole Line Road Overcrossing on Ambient Levels of Selected Pollutants at the Calgene Facilities," Sierra Research Report No. SR93-09-01, prepared for the City of Davis, September 1993.

"Leveling the Playing Field for Hybrid Electric Vehicles: Proposed Modifications to CARB's LEV Regulations," Sierra Research Report No. SR93-06-01, prepared for the Hybrid Vehicle Coalition, June 1993.

"Size Distributions of Trace Metals in the Los Angeles Atmosphere," *Atmospheric Environment*, Vol. 27B, No. 2, pp. 237-249, 1993.

"Preliminary Feasibility Study for a Heavy-Duty Vehicle Emissions Inspection Program in the Lower Fraser Valley Area," Sierra Research Report No. 92-10-01, prepared for the Greater Vancouver Regional District, October 1992.

"Development of Mechanic Qualification Requirements for a Centralized I/M Program," SAE Paper No. 911670, 1991.

"Cost-Effectiveness Analysis of CARB's Proposed Phase 2 Gasoline Regulations," Sierra Research Report No. SR91-11-01, prepared for the Western States Petroleum Association, November 1991.

"Origins and Control of Particulate Air Toxics: Beyond Gas Cleaning," in Proceedings of the Twelfth Conference on Cooperative Advances in Chemical Science and Technology, Washington, D.C., October 1990.

"The Effect of Gasoline Aromatics on Exhaust Emissions: A Cooperative Test Program," SAE Paper No. 902073, 1990.

"Estimation of the Impact of Motor Vehicles on Ambient Asbestos Levels in the South Coast Air Basin," Paper No. 89-34B.7, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"Benzene/Aromatic Measurements and Exhaust Emissions from Gasoline Vehicles," Paper No. 89-34B.4, presented at the 82nd Annual Meeting of the Air and Waste Management Association, Anaheim, CA, June 1989.

"The Impact of Diesel Vehicles on Air Pollution," presented at the 12th North American Motor Vehicle Emissions Control Conference, Louisville, KY, April 1988.

"Exhaust Benzene Emissions from Three-Way Catalyst-Equipped Light-Duty Vehicles," Paper No. 87-1.3, presented at the 80th Annual Meeting of the Air Pollution Control Association, New York, NY, June 1987.

"Trends in Emissions Control Technologies for 1983-1987 Model-Year California-Certified Light-Duty Vehicles," SAE Paper No. 872164, 1987.

Exhibit "C"

COMMENTS ON THE JUNE 20, 2016 PROPOSED MODIFICATIONS

Prepared by:
H-D Systems
Washington, D.C.
July 3, 2018

OVERVIEW

The Energy Efficiency ratio (EER) is the ratio of energy use by the alternative fuel vehicle to the energy used by a similar conventional vehicle per unit travel distance. The ARB has documented the EER values for several alternative fuel vehicle types in Appendix H of the 2018 Initial Statement of Reasons (ISOR) for amendments to the LCFS. H-D Systems had submitted a report which examined the EER values in Appendix H of the ISOR to assess its reasonableness using both an engineering analysis and an assessment of the similarity of vehicle types and tests used to generate the data underlying the EER. The ARB has published modifications to the ISOR in its recent June 20th proposed 15-day modifications to the original proposal detailed in the ISOR. Unfortunately, the ARB's proposed modifications have largely retained the original EER values or changed them in a directionally incorrect way, and the ARB does not appear to have reviewed the H-D Systems' report submitted in response to the ISOR. In addition, new EER values have been proposed for cargo handling vehicles at ports, and the EER for auxiliary engines in ocean-going vessels while docked at port. FF56-68

SUMMARY OF EARLIER RECOMMENDATIONS

Our earlier report had provided analyses that suggested that reducing many of the EER values contained in the ISOR. The main reasons for these suggested reductions are

- The EER values for CNG vehicles do not account for the bulky tanks to carry CNG which reduce the energy efficiency of the vehicles and reduce payload capacity for cargo vehicles. FF56-69
- The EER values for battery electric vehicles do not account for the significant energy loss under cold ambient conditions and for the loss of payload capacity due to the weight of the batteries. FF56-70
- The EER values for many passenger vehicles, both light and heavy duty, do not account for the heating, ventilation and air conditioning loads that can have much more serious impacts on electric vehicle efficiency relative to conventional gasoline and diesel vehicles FF56-71
- There are inconsistencies in the proposed EER for some of the vehicle types when comparing the proposed values in relation to diesel versus gasoline vehicles. FF56-72
- The EER values for fuel cell vehicles are not consistent with vehicle fuel economy certification data. FF56-73

The earlier results are summarized in the table below from the H-D Systems report to which the values published in Table 1, Appendix A of the June 20th document have been added. As can be seen, some of the newer values have been increased rather than decreased from those published in the ISOR. ARB has not provided any rationale for the changes and has not addressed any of the issues raised in the H-D Systems report. FF56-74

Vehicle Type	EER published in ARB ISOR	EER in Appendix A of the June 20th ARB Proposal	Suggested Correction in H-D System Report	
Battery Electric Cars (LDV)	3.0	3.4	2.7, could be reduced by 10 to 15% in summer and winter	FF56-75
Battery Electric Light Duty Trucks (LDT)	3.0	3.4	2.7, plus payload reduction in cargo trucks	FF56-76
Hydrogen Fuel Cell LDV	2.3	2.5	About 2.0, weather effects unknown	FF56-77
CNG LDV/LDT	1.0	1.0	0.9 for aftermarket conversions	FF56-78
LPG Bus	0.9	0.9	0.74 at urban speeds (<20 mph)	FF56-79
Electric TRU	3.4	3.4	ARB data too variable for conclusion	FF56-80
Electric Motorcycles	4.4	4.4	Probably closer to 3.5, need data	FF56-81
Electric Bus	4.8 at urban speed	5.0?	About 3 as an all-season average	FF56-82
Parcel and Drayage Trucks	4 to 5.5	5.0?	Payload loss, seasonal effects and diesel idle shutoff not accounted for.	FF56-83

The revisions made by ARB to the EER values in the table above are not documented in any of the appendices to the June 20th Proposed Modifications. FF56-84

ADDITIONAL CATEGORIES WITH EER VALUES

Attachment D to the June 20th Proposed Modifications lists EER values for Cargo Handling Equipment and Ocean-going Vessels. Limited documentation is provided for the EER values derived in Attachment D. FF56-85

Cargo Handling Equipment

The derivation of EER values for cargo-handling equipment is based on a modeled relationship between engine efficiency and load factor. The average load factor for different cargo handling equipment is based on load factors used for emission inventories and from recent work for the Port of Los Angeles. The documentation states that CARB's EER calculation methods assume no losses of energy during battery charging or conversion of energy to useful work. To be consistent with prior calculation methods, staff assumed no losses for electrical non-yard truck equipment, i.e. the efficiency is 100%. Therefore, the inverse of diesel engine efficiency is used to estimate EERs for the ratio of electrical equipment to diesel equipment.

ARB utilizes a model to estimate the efficiency of a diesel engine as a function of the load factor imposed on the engine. While the modeled relationship between diesel engine efficiency and load factor is consistent with engineering principles, there is little documentation on the load factors listed by equipment type in Appendix D. Table 1 of Appendix D also lists an "hours of operation" by equipment type that is footnoted but the footnote itself is missing. It is unclear what the hours of operation refers to as it varies by equipment type from 1900 to 401,633 so it is clearly not the annual use rate. FF56-86

The load factors span the range from 0.2 to 0.59 but the derived EER is 2.6. Since the EER is the inverse of engine efficiency, the estimated average efficiency is 1/ 2.6 or 38.5%. The peak efficiency (the highest value) for a diesel engine, which typically occurs at load factors of 0.85 to 0.9, is 41% to 42% so that an operating average efficiency so close to the maximum value seems unreasonably high. Appendix D also states that diesels operate at average efficiency between 30 and 35%, so that the EER is inconsistent with ARB's own findings.

It is unclear why the ARB assumes no losses of energy during battery charging or conversion of energy to useful work for electric equipment, as these losses are about 20 to 25% of total energy use (about 5% to 8% in battery charge-discharge and 15 to 18% in motor and controller losses). The high average efficiency of the diesel engine indicated by the EER is also of concern and both assumptions should be reviewed.

Ocean Going Vessels (OGV)

When OGVs are "at-berth," or docked in a harbor, an auxiliary diesel engine(s) provides electrical power for equipment used while the vessel is at rest. Power needs while at-berth FF56-87 include support for on-board electronics, lighting, ballast pumps, ventilation systems, and air-conditioning. The ARB analysis quantifies an aggregated EER value for a wide range of auxiliary engines on all types of ships that call California ports (but does not include/pertain to boilers that are used in some vessels instead of diesel engines). The recommended EER quantifies the increased energy efficiency of using shore power instead of using the conventional on-board auxiliary diesel engine. The analysis assumes all of the electric energy would be provided by the local utility even though some California ports are able to generate a portion of their own electricity. The potential differences in carbon intensity between power self-generated by the port and power from the grid is ignored in the EER calculation. For consistency with prior EER calculations, ARB staff also assumed that shore power is 100% energy efficient. Hence, the EER is simply the inverse of auxiliary engine efficiency, similar to the methodology used for cargo handling equipment.

Not surprisingly, the EER computed by ARB is 2.6 for OGV, which is identical to the one for cargo handling equipment. The EER estimate is based on data from a consultants' report[1] on the emissions from vessels at the Port of Long Beach, and this report lists both emissions and electric power generated by the vessels while docked. In this report, the electric power generated by ships was computed from <u>assumptions</u> about hoteling loads and the CO2 emission estimates were derived by using <u>estimates</u> of fuel consumption versus load for the auxiliary engines. Since both fuel consumption and electric power are not based on measured values but are estimated values using an assumed efficiency, the EER calculation performed by ARB uses these estimates to simply reproduce the original assumption of engine efficiency made by the consultants. FF56-87 cont.

In the case of OGV, the auxiliary engine provides electric power which is replaced by power from the grid, so that the ARB methodology of using of the inverse of engine efficiency for EER is defensible for OGV auxiliary power. However, the data from which the EER is estimated by ARB are not based on actual measurements but on a set of assumptions employed by the consultants to the Port of Long Beach. The ARB methodology should rely on actual data from auxiliary engine tests or actual measurements of power output and fuel consumption by OGV auxiliary engines.

[1] Starcrest Consulting Group, Port of Long Beach 2016 Air Emissions Inventory, July 2017

Curriculum Vitae
For
K.G. Duleep

K.G. Duleep

President, H-D Systems

EDUCATION

M.B.A., Finance, Wharton School, University of Pennsylvania, Philadelphia, PA, 1989

Doctoral Candidate, Aerospace Engineering – Combustion, University of Michigan, Ann Arbor, MI, 1976

M.S., Aerospace Engineering/Computer Information and Control Engineering, University of Michigan, Ann Arbor, MI, 1975

Bachelor of Technology, Aerospace Engineering, Indian Institute of Technology, Madras, India 1972

EXPERIENCE OVERVIEW

K.G. Duleep is President of H-D Systems, a new consulting firm which is a spin-off of the EEA automotive technology group, in the Washington, DC metropolitan area. His extensive work on vehicle energy use, cost and performance of fuels and engine technology and manufacturing costs have been widely cited around the world. Through his work, he meets periodically with the technical staffs of most of the world's largest auto-manufacturers to discuss new technology and has obtained key insights on vehicle development through this process. He is well known for his work on vehicle fuel economy technology and his CAFE forecasts under alternative scenarios have been the basis for many regulatory and policy discussions in Congress. In 2008/9, he directed analyses as a support contractor to the National Academy of Sciences Committee on Fuel Economy Standards, and he is currently involved in the new CAFE standards for the post-2016 time frame. He has also performed studies on life cycle energy use and the energy use in vehicle manufacturing. He was the developer of the fuel economy forecasting algorithm embedded in NEMS, which he and his group has updated periodically.

PROJECT EXPERIENCE

Fuel Economy Modeling and Forecasting, EIA and CEC, 1990 –Present. Developed detailed forecasting models of light and heavy vehicle fuel economy that are modules within the NEMS model and the CALCARS models. Models were periodically updated by Mr. Duleep over the last 20 years.

Automotive Technology Cost Analysis, Department of Energy, ongoing. Direct multi-year task order contract with DOE'S Policy Office to evaluate costs and benefits of new automotive technologies. Also serve as technical lead on advanced engine technology analysis. Coordinate efforts of two major subcontractors. Most recent project in 2014-15 covered engine technology potential from use of 98 octane E25 (25% ethanol) blends.

Technology Planning, U.S. Oil Refiners, Japanese Auto manufacturers, 1996–Present. Provides technology planning and emissions compliance support to oil refiners and import auto manufacturers. The work involves detailed assessment of new technology for vehicles and estimation of their impact on vehicle fuel economy, cost, drivability and reliability. Forecast of technology penetration in different markets and segments of the fleet are also part of the services provided.

Alternative Fuels Outlook, Califoria Energy Commission, Led the study of alternative fuel vehicles as a means of reaching California's GHG reduction goals. Reported on the current state of vehicles and forecasted the economic viability of alternative fuels in the state considering potential roadblocks such as higher costs and increased weight. Estimated the required capital requirements for any incremental infrastructure that may be necessary. Provided strategic recommendations on investment priorities and mechanisms to accelerate commercialization of alternative fuels and technologies.

Analaysis of Fuel Cell/ Hydrogen Power in Non-Automotive Markets, US DOE, 2009-2010. Examined the potential for PEM fuel cells in diverse markets like stand-by power, fork lift trucks, and combined residential heat and power for the US. Work was a follow-on to a market penetration analysis for fuel cells in automotive markets.

An overview of Electric Vehicles and Plug-in Hybrid Electric Vehicles, European Commission Directorate-General Environment. Provided consultation to the EU concerning the impacts of an attributes-based standard such as weight-based standards on fuel economy and GHG emissions. Created a simple model that could verify the results of a very complex model with hundreds of inputs.

Analysis of Light Duty Vehicle Weight Reduction Potential, Department of Energy, Directed a large scope of study focusing on weight reduction technologies as capable of significant fuel economy improvement at potentially low costs. Utilized the staff capabilities developed in this area as a result of weight reduction analysis for the US EPA, California Air Resources Board (ARB) and other clients. Conducted high level meetings with weight reduction experts through his extensive contacts in the auto-industry and the Tier I supplier base.

PUBLICATIONS AND REPORTS

Mr. Duleep has over 50 publications in technical society and peer reviewed journals and has authored over 200 reports to clients. He also has authored two encyclopedia articles on Internal Combustion engine efficiency.

AWARDS/HONORS

SAE Award for Contribution to Public Policy Analysis, 2011

Directors List (First Rank), Wharton School, 1989

Merit Scholarship, University of Michigan, 1974

First Prize Winner, University Science Fair, India, 1971

PROFESSIONAL AFFILIATIONS

Tau Beta Pi (Engineering Honor Society)

Society of Automotive Engineers

LANGUAGES

English, Hindi and Tamil

EMPLOYMENT HISTORY

ICF International	Managing Director	2007-2011
Energy and Environmental Analysis, Inc.	Managing Director	1997-2007
Energy and Environmental Analysis, Inc.	Director	1988-1997
Energy and Environmental Analysis, Inc.	Senior Consultant	1979-1988
Bendix Electronics and Engine Control Systems Group	Senior Engineer	1976-1978
Aeronautical Development Establishment (India)	Junior Scientific Officer	1972-1973

Exhibit "D"

[redacted]

Subject: FW: BIOFUELS UPDATE: ***CARB Seeking Feedback in 15-Day Comment Period for LCFS Proposals

From: alertsadmin@opisnet.com <alertsadmin@opisnet.com>
Sent: Monday, June 25, 2018 4:54 PM
To: [redacted]
Subject: BIOFUELS UPDATE: ***CARB Seeking Feedback in 15-Day Comment Period for LCFS Proposals

2018-06-25 04:54:04 EDT
***CARB Seeking Feedback in 15-Day Comment Period for LCFS Proposals

The California Air Resources Board (CARB) late last week released its proposed 2018 Low Carbon Fuel Standard (LCFS) rule-making that included several key modifications and amendments.

Publication of the proposed regulation on the agency's website on Thursday launched a 15-day comment period that will close July 5. CARB is hoping to make the changes effective in January.

The first and only comment posted to CARB's website as of Monday afternoon was from Occidental Petroleum, which focused on the carbon capture and sequestration protocol under the LCFS. Multiple sources on Monday indicated plans to submit comments, likely by the end of this week or before the July Fourth holiday.

"There are plenty of moving parts in the proposal -- people are somewhat concerned by a few aspects of the changes they're trying to make," one stakeholder source said Monday. "But I'm confident those concerns will be voiced in the comment period, and hopefully, CARB will be willing to listen." FF56-88

The proposed rule is largely in line with what agency staff presented at a June 11 workshop, where several of the planned proposals were met with questions and occasional pushback from stakeholders, particularly language that would allow hydrogen fueling stations and fast-charging electric vehicle stations to generate LCFS credits on the basis of capacity rather than actual fuel used.

At the workshop, CARB discussed how it envisions its LCFS zero-emissions vehicles (ZEV) Infrastructure crediting provisions to work. California Gov.
Jerry Brown in an April executive order directed all state entities to work with the private sector to spur the construction and installation of 200 hydrogen fueling stations and 250,000 ZEV chargers, including 10,000 direct current (DC) fast chargers, by 2025.

Under the plan, CARB proposed to allow both types of fuel dispensing installations to generate LCFS credits up to a certain level to support infrastructure growth. CARB said it intends to stop approving applications for DC chargers or hydrogen refueling stations if infrastructure credits exceed 2.5% of deficits generated in the previous quarter. As hydrogen and electricity utilization goes up, the infrastructure credits will automatically decrease.

"It's certainly a philosophical departure from what the program has been about in the past on fuel neutrality," CARB Transportation Fuels Manager Sam Wade said. "We acknowledge that these credits do not represent actual greenhouse gas emissions reductions. We will be explicit and will be able to quantify how many of these credits we have issued and when making claims about the reductions the program has accomplished, we will remove those credits."

Wade said the CARB board told his group to move expeditiously on the ZEV infrastructure crediting rollout.

CARB also discussed its plans to end the state's Alternative Diesel Fuel (ADF) regulations. The agency said it is proposing to bifurcate the sunset provisions for on-road applications -- likely 2023 -- and off-road -- likely 2030 or later -- which will occur when 90% of that sector is equipped with New Technology Diesel Engines (NTDEs). It's a departure from CARB's original proposal, which lumped both on- and off-road applications together, and envisioned closing out the ADF regs when both applications reached the 90% NTDE level.

CARB also discussed modifications to its third-part verification proposal, including adding requirements to allow verifier quarterly review of submitted data as part of the annual verification services as well as clarifying language for potential conflicts of interest.

FF56-88 cont.

CARB further said it wants to allow for the contracting for future delivery of LCFS credits for forward and future trading, adding that when a trade is agreed to, it should be reported in the LCFS Reporting Tool (LRT). This is not a change in philosophy, CARB noted. The Intercontinental Exchange (ICE) launched LCFS futures trading based on OPIS settlements on May 21, and there have been roughly a dozen trades in the first month of trading.

CARB also provided updates to the Carbon Capture and Sequestration (CCS) program, technical updates to the CA-GREET 3.0 model for carbon intensity (CI) values alongside new Tier 1 simplified CI calculators.

--Jordan Godwin, jgodwin@opisnet.com

SF_CF2_SF14

August 30, 2018

Mr. Sam Wade
California Environmental Protection Agency
Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Comments Submission
X. Modification to In-Use requirements for Specific ADFs Subject to Stage 3A
Section 2293.6 of the ADF Regulation

Dear Mr. Wade,

Thank you for the opportunity to submit comments specific to the subject matter. California Fueling has previously submitted (6/26/18) comments outlining practical concerns associated with bifurcation. Beyond the practical concerns, there are technical concerns associated with bifurcation which are outlined following.

Sunset of Biodiesel In-use Requirements – On-Road Vehicle Concerns

Two recent studies, as outlined following, highlight the concerns associated with NTDE's, Selective Catalytic Reduction (SRC) and NOX emissions. One study focuses on SCR operation whilst the other study focuses on biodiesel's impact on SCR operation. SF14-1

- Karavalakis, G., Jiang Y., Yang, J., Durbin T. et al., "Emissions and Fuel Economy Evaluation from Two Current Technology Heavy Duty Trucks Operated on HVO and FAME blends," *SAE International Journal of Fuels & Lubricants, Volume 9, Issue 1 (April 2016)*
- Kanok Boriboonsomsin, Kent Johnson, George Scora, Daniel Sandez, Alexander Vu, Tom Durbin, and Yu (Jade) Jiang, "Collection of Activity Data from On-Road Heavy-Duty Diesel Vehicles, FINAL REPORT, (ARB Agreement No. 13-301)", May 2017

The SAE paper studied 2 vehicles (2014 Cummins ISX15 and 2010 Cummins ISB6.7), under two modes of operation (EPA Urban Dynamometer Driving Schedule and CARB's Heavy-Duty Diesel Truck Transient Cycles) and concluded that biodiesel (B20) showed a statistically significant increase in NOX versus CARB diesel in both vehicles over both cycles. The authors theorized on the mechanisms of NOX production as well as the negative impact biodiesel has on SCR operation both of which are evidentiary support of NOX emission increases observed in NTDE's.

CALIFORNIA
FUELING

Specific to SCR operation, the authors indicated that the SCR's on vehicles studied did not negate biodiesel's effect on NOX emissions but rather contributed to such.

The May 2017 Air Resources Board report studied a much broader selection of vehicles (approximately 90) representative of the NTDE fleet (EMFAC2011). "One of the primary objectives of this research is to identify the fraction of vehicle operation that SCR may not control NOx effectively." The key conclusion of the study specific to SCR operation was as follows:

SF14-1 cont.

> "Overall, it is found that on average the vehicles in this study operate with SCR temperature lower than 250 °C for 42-91% of the time and lower than 200 °C for 11-87% of the time, depending on their vocation. These portions of vehicle operation with low SCR temperature have a significant implication on the vehicles' real-world NOx emission. By assuming a generic NOx reduction curve as a function of SCR temperature for all the vehicles, the weighted average %reduction in engine-out NOx emission ranges from 16% for agricultural trucks to 69% for refuse trucks. This would have a significant impact on the NOx emission inventory of heavy-duty diesel vehicles in California."

Put a different way, SCR's in NTDE's do not operate properly 31-84% of the time.

The combination of biodiesel, its negative impact on SCR operation and ARB's study indicating California, fleet representative, NTDE's do not provide expected NOX reduction provides no reasonable basis for CARB to bifurcate an on and off-road sunset provision based on either vehicle population age or vehicle miles travelled. Furthermore, our June 2018 comment submission supports the impractical nature of applying a bifurcation concept because of its potential adverse effect on NOX.

We believe that all things considered, bifurcation is not prudent or in the best interest of the public at this time – the risk is more than the reward. There are just too many unknowns and the better decision would be to readdress bifurcation once more progress is made with the ADF.

We sincerely appreciate the opportunity to comment on CARB's LCFS proposed amendments. As always, we look forward to working with CARB through the rulemaking process.

Sincerely,

Pat

Patrick J. McDuff
CEO

CALIFORNIA FUELING

SF_CCAALACVAQ1_SF16

August 30, 2018

Mary Nichols, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Support for Low Carbon Fuel Standard

Dear Chair Nichols and Members of the Board:

On behalf of the undersigned organizations, we write to encourage the California Air Resources Board to move forward with the adoption of the 2030 Low Carbon Fuel Standard as an important component of achieving California's clean air and climate standards. The LCFS is a core program addressing the many harms caused by the transportation fuels sector, and spurring the transition away from combustion of fossil fuels. The LCFS provides leadership on this critical issue, protects public health and our environment while spurring innovation and modeling successful climate policy. SF16-1 continues to last page

Comments on Low Carbon Fuel Standard Amendments

We strongly support amending the LCFS with higher percentages, inclusion of alternative jet fuels, updated carbon intensity values and energy efficiency ratios for freight and transit, and a point-of-purchase incentive program for zero-emission vehicles. The LCFS is already helping to reduce greenhouse gas emissions and air pollution by starting the process of diversifying our transportation fuel mix, and needs to be ramped up to maximize progress toward that goal. The LCFS increases the use of alternative vehicle fuels like electricity, hydrogen, renewable diesel and renewable methane, reducing our reliance on petroleum and spurring greater transition to zero emission transportation solutions. The LCFS is playing a critical role in supporting the transition of transit buses, fork lifts and other vehicles to electric drive technologies. SF16-2

2030 Carbon Intensity Target

We support the 2030 target for reducing the carbon intensity of transportation fuels by 20%. This target is achievable by continuing the growth of alternative fuels. The LCFS will make a major contribution to California's efforts to reach its 2030 standard of reducing greenhouse gas emissions by 40% from 1990 levels by 2030. In addition, a strong LCFS will reduce the localized air pollution, caused primarily by combustion of fossil fuels for transportation,that continues to damage the health of millions of Californians. SF16-3

Inclusion of Alternative Jet Fuels

We support the inclusion of alternative jet fuels in the LCFS as a way to address this significant and growing source of GHG emissions. Reducing emissions from aviation has been difficult, and inclusion in the LCFS will help to shift jet fuels toward more sustainable alternatives to petroleum. SF16-4

Hydrogen Fueling Capacity Credits
We understand the intention behind the provisions related to capacity credits for fast-charging hydrogen fueling infrastructure, but remain concerned with the potential for over-crediting for un-capped credit generation under this amendment. If this proposal is to be implemented, we support a thorough review of hydrogen station capacity credit generation to ensure that the environmental benefits of the program are not impacted by excess credit generation that may not reflect low carbon fuel deployment, and would encourage the board to revise the program as needed. SF16-5

The Role of the LCFS in Zero Emission Transportation
The electricity pathway within the LCFS is an important tool to support the Governor's goals of placing more than 1.5 million Zero-Emission Vehicles (ZEVs) on California roads by 2025 and 5 million by 2030. The LCFS amendments before the board provide important updates to the energy efficiency metrics for zero emission trucks and buses, and include credit-generation opportunities for zero emission Transportation Refrigeration Units, cargo-handling equipment and shore power to advance sustainable freight in California. These credits provide an important signal for a broader transition to zero emissions technologies across the transportation fuel sector and should be advanced by the Board. Working together, zero emission LCFS credits, state incentive programs and strong, binding regulations can accelerate the critical transition away from petroleum fuels across the transportation sector. SF16-6

Point-of-Purchase Incentive for Zero-Emission Vehicles

While the updated zero emission transportation provisions support broader electrification, the current program does not fully utilize the LCFS' potential to create incentives for the purchase of ZEVs. We support the creation a statewide "on the hood" clean fuel reward for new EV buyers, which would be administered by a statewide third-party administrator, subject to approval by CARB, based on residential charging data recorded by the vehicles. Point-of-sale incentives are the most effective way to drive consumer ZEV adoption, especially for non-affluent buyers.

This approach provides significant consumer benefits and improves upon the existing program design. We support the staff proposal to require, in the regulation, a minimum utility percentage contribution to the statewide rebate program. This threshold will assure that incentives reach meaningful amounts. SF16-7

We support the staff proposal to add four tiers to determine the rebate amount based on battery capacity of the EV, similar to federal tax credit tiers. This would ensure EVs with higher battery capacity get higher rebates as compared to EVs with lower battery capacity, and will help to accelerate deployment of stronger battery plug-in hybrids that meet most of the usual driving needs of consumers.

Similar to other existing state ZEV programs, we also recommend that the Point-of-Purchase program incorporate a means test, to maximize the effectiveness of incentives by reserving them for non-affluent Californians purchasing non-luxury vehicles.

We urge CARB to take action this year to implement these changes so that California can accelerate progress toward our bold targets for EV adoption, low carbon fuel use and air quality improvements.

SF16-1 continued from first page

Respectfully Submitted,

Bill Magavern

Bill Magavern
Policy Director
Coalition for Clean Air

Will Barrett
Clean Air Advocacy Director
American Lung Association

Dolores Barajas-Weller
Director
Central Valley Air Quality Coalition (CVAQ)

SF_GROWTHENERGY3_SF31

STATE OF CALIFORNIA

AIR RESOURCES BOARD

PROPOSED AMENDMENTS TO THE LOW CARBON FUEL STANDARD REGULATION AND TO THE REGULATION ON COMMERCIALIZATION OF ALTERNATIVE DIESEL FUELS

**GROWTH ENERGY'S RESPONSE
TO THE "SECOND NOTICE OF PUBLIC AVAILABILITY OF MODIFIED TEXT AND AVAILABILITY OF ADDITIONAL DOCUMENTS AND INFORMATION," DATED AUGUST 13, 2018, AND AUGUST 15, 2018, ERRATA**

AUGUST 30, 2018

For further information contact:
Mr. Chris Bliley
Vice President of Regulatory Affairs
Growth Energy
CBliley@growthenergy.org
202-545-4000

Comments of Growth Energy on the "Second Notice of Public Availability of Modified Text and Availability of Additional Documents and Information" Concerning the Proposed Amendments to the Low Carbon Fuel Standard Regulation and to the Regulation on Commercialization or Alternative Diesel Fuels, and Related Errata

Growth Energy respectfully submits these comments on the August 13, 2018, Second Notice of Public Availability of Modified Text and Availability of Additional Documents and Information, and the August 15, 2018, Errata (collectively, the "Second 15-Day Notice") related to the California Air Resources Board's ("CARB") proposed amendments to the Low Carbon Fuel Standard Regulation (the "LCFS") and the proposed amendments to the Regulation on Commercialization or Alternative Diesel Fuels (the "ADF"). Collectively, the proposed amendments to the LCFS and ADF regulations are referred to in these comments as the "Proposed Amendments," while the proposed modifications to the LCFS and the ADF regulations identified in the Second 15-Day Notice are referred to as the "Proposed Modifications." These comments are also accompanied by expert reports prepared by (i) Thomas Darlington of Air Improvement Resource Inc., and (ii) Jim Lyons of Trinity Consultants, which are enclosed as Exhibits "A" and "B," respectively.

Modifications to the GREET Model. As an initial matter, Growth Energy appreciates CARB staff's recommended modifications to the GREET model. Among other things, CARB has clarified its treatment of haul and backhaul emissions, corrected issues concerning medium and heavy-duty truck emissions, and corrected its calculation of the nitrogen content for sugarcane ethanol. SF31-1

That said, there are still several issues with the GREET model that should be modified to ensure the LCFS is based on "the best available economic and scientific information." (Health & Saf. Code, § 38562, subd. (e).) In addition to the unresolved issues raised previously by Growth SF31-2a

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Energy, GREET should be revised to include a distillers grains enteric fermentation credit for corn ethanol, and ensure that the credit is based on conditions in the United States (in contrast to Hünerberg, *et al.*). (See Exhibit "A"). As we have urged in the past, CARB should also incorporate the latest indirect land use change values from the GTAP model into GREET. (*Id.*) SF31-2a cont. SF31-2b

Capacity Credits for Electric/Fuel Cell Infrastructure. In addition, Growth Energy continues to have concerns regarding the proposal to provide capacity credits for electric and fuel cell vehicle infrastructure. As demonstrated in Exhibit "B," the alleged GHG benefits of the LCFS regulation would decrease significantly if the Proposed Modifications are adopted. Specifically, assuming the LCFS does not result in fuel shuffling, "the annual amount of GHG reductions that would not be realized by the LCFS program due to the proposed infrastructure crediting provisions would range from about 0.8 to 1.6 $MMTCO_2eq$ per year and the cumulative loss in GHG emissions from 2019 to 2030 could amount to 14.0 $MMTCO_2eq$." (Exhibit "B" at 1.) This result is inconsistent with AB 32 and SB 32. (See Health & Saf. Code, §§ 38560.5, subd. (c); 38562, subd. (a); 38566.) SF31-3

The Proposed Modifications would also result in a substantial amount of windfall revenue to operators and owners of DC fast charge and hydrogen stations which could total $150 to $300 million per year. (Exhibit "B" at 1.) These benefits will in turn reduce the incentives for alternative fuel providers to sell low CI fuel in the aggregate amount of $150 to $300 million per year, contrary to the purpose and intent of the LCFS program. SF31-4

CARB Should Consider Alternatives to the LCFS. Rather than trying to convert the LCFS regulation into something it was never intended to be, CARB should look to reasonable alternatives to the LCFS that would achieve the same purposes and results, but without its significant unintended consequences. Specifically, CARB should consider the alternatives Growth Energy SF31-5

3

raised in its April 27, 2018 and July 5, 2018 comments, which include the "WSPA Alternative" (AB 32 Cap and Trade program) and the "E15 Alternative," as well as the proposal described in Exhibit "B" at pages 2-3, which advocates for the use of surplus funds from the point of purchase rebate program provided to EDUs for residential EV charging as a source of funding to support underutilized DC fast charging and hydrogen stations. These alternatives would each lessen the "significant and unavoidable" effects of the Proposed Amendments, and the LCFS regulation generally, (Pub. Res. Code, § 21002), and help reduce greenhouse gas emissions "to at least 40 percent below the statewide greenhouse gas emissions limit no later than December 31, 2030," in a manner that is both technologically feasible and cost-effective. (Health & Saf. Code, § 38566.) SF31-5 cont.

Verification of Fuel Pathways. Growth Energy also has concerns regarding CARB's proposal to require verification of all fuel provider pathways. This proposed process is unnecessary because it would be duplicative of the work already performed as part of the pathway approval, and would add significant expense by requiring fuel providers to retain verifiers. This is of significant concern because CARB's proposed conflict of interest (COI) requirements are exceedingly stringent, and would dramatically limit the number of qualified third-party verifiers competent to serve as verifiers. Before considering the Proposed Amendments for adoption, CARB should survey the range of potential consultants available to serve as verifiers, and confirm the work is capable of being performed in a timely and cost-effective manner by existing competent professionals. Moreover, instead of requiring all alternative fuel producers to be subject to verification, CARB should instead impose random third-party verification for a small subset of alternative fuel producers each year (*i.e.*, 5%). Random verification would be equally effective in ensuring compliance, but without the significant expense associated with *requiring* continuing verification for all alternative fuels. (See Exhibit "B" at 6.) SF31-6

Thank you again for the opportunity to participate in this rulemaking, and your anticipated consideration of the above comments.

GROWTH ENERGY'S RESPONSE TO THE "SECOND NOTICE OF PUBLIC AVAILABILITY OF MODIFIED TEXT AND AVAILABILITY OF ADDITIONAL DOCUMENTS AND INFORMATION," DATED AUGUST 13, 2018, AND AUGUST 15, 2018, ERRATA

EXHIBIT "A"

Comments on CARB's Second15-day Notice
August 30, 2018
Thomas Darlington, Air Improvement Resource Inc.

This document summarizes my comments on CARB's Second 15-day Notice materials.

Indirect Land use Changes

In its second 15-Day Modifications, CARB did not address our comments on CARB's First 15-Day Notice, submitted on behalf of Growth Energy, on utilizing a more recent version of the GTAP model. The LCFS should be modified to address each of these concerns. SF31-7

Direct Emissions of Corn Ethanol, Corn Oil, and Sugarcane Ethanol

Distillers Grains Enteric Fermentation Credit for Corn Ethanol

In this latest version of the Proposed Modifications to the LCFS, CARB still did not include a distillers grains enteric fermentation credit for corn ethanol. CARB, however, in their Errata document listed a new reference:

> Feeding high concentrations of corn-dried distillers' grains decreases methane, but increases nitrous oxide emissions from beef cattle production, Agricultural Systems 127 (2014): 19-27. Hünerberg, M., Little, S.M., et al., Available at: https://www.sciencedirect.com/science/article/pii/S0308521X14000146?via%3Dihub..

SF31-8

This reference was included presumably to counter our prior comment about reduced methane from cattle fed dried distillers grains (DDGs). As the title indicates, the article is presenting evidence that N_2O emissions increase with cattle fed DDG, and that this increase in N_2O emissions negates the reduced methane emissions (i.e., enteric fermentation credit). The increase is due to higher emissions of N_2O from cattle manure when fed either corn DDGs or wheat DDGs. The article indicates:

> Using high-fat distillers grains in the diet of feedlot cattle may decrease enteric CH_4 emissions, but *at high dietary levels* it increases N excretion and results in a net increase in GHG emissions *(emphasis added).*

However, in reviewing the article, it is apparent that the evidence presented is not applicable to the U.S. Specifically, the evidence is based on cattle fed with 40% DDGs, which does not reflect U.S. conditions. This is also inconsistent with the assumptions in Argonne's GREET model, which assumes a DDG dietary inclusion rate of 22-23%, about half of the amount used in a case study described in this article.[1] The inclusion rate would have a direct effect on N_2O emissions. Using a much lower DDG inclusion rate than 40% would result in no increase in N_2O emissions from cattle fed DDGs. Thus, because the experiment conducted in this research is not applicable to the inclusion rates in the U.S., CARB should include the enteric fermentation credit in CaGREET2.0. SF31-8 continued from previous page, continues to footnote below

Rail and Barge Transport

Thank you for considering our comments concerning the removal of backhaul emissions, and clarifying that the energy intensities CARB is using are for the haul and backhaul combined. SF31-9

Medium and Heavy-Duty Truck Emissions

Thank you for considering Growth Energy's prior comments concerning medium and heavy-duty truck emissions, and in particular, recognizing that the fuel economy of both vehicle classes were too low and that the fuel economy for the backhauls should be better than the haul. SF31-10

Sugarcane Ethanol

Nitrogen Content of Sugarcane Straw

Thank you for considering Growth Energy's comments on the nitrogen content of sugarcane straw and increasing this value from 0.37% to 0.53%, based on the average value from several literature sources, instead of just the lowest value. SF31-11

Summary

We appreciate the fact that CARB has incorporated some of our prior comments on the GREET model. However, in order to be consistent with the best available scientific data, the GREET should be further modified to incorporate all of our prior comments. In summary, the latest version of the GREET model should be modified to include the DG enteric fermentation credit for corn ethanol. SF31-12 continues to next page In addition, as I have indicated in previous comments, CARB should revise estimates of emissions related to indirect land-use changes using the latest version of GTAP. SF31-13

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[1] *Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis,* Arora, S., Wu, M., and Wang, M., Energy Systems Division, Argonne National Laboratory, September 2008, ANL/ESD/11-1. See Table 11 of this report for dietary inclusion rates in the U.S. SF31-8 continued from above

Attachment 1

Biodiesel CIs from CaGREET2.0 Versions

Mar-18	**Corn Oil from DGS of Dry Mill Ethanol to Biodiesel**									
	g/MMBtu	Corn oil Extraction	Corn Oil Transport	Corn oil Debit	BD production	BD T&D	Total CI	Tank-to-Wheel	LUC	Final CI, g/MJ
	VOC	0.36	0.19		2.40	0.96	3.90			3.90
	CO	1.46	0.62		5.75	3.15	10.98			10.98
	CH4	6.35	1.28		37.07	3.62	48.32			48.32
	N2O	0.06	0.00		0.18	0.03	0.27			0.27
	CO2	2982.07	552.48		11148.76	1619.74	16303.05			16303.05
	Subtotal gCO_2e/MJ	**3.00**	**0.56**	**11.17**	**11.51**	**1.64**	**27.87**	**0.76**	**0.00**	**28.63**
	Adjustment	**2.84**	**0.53**	**10.59**	**10.92**	**1.64**	**26.52**	**0.76**	**0.00**	**27.28**
Jul-18	**Corn Oil from DGS of Dry Mill Ethanol to Biodiesel**									
	g/MMBtu	Corn oil Extraction	Corn Oil Transport	Corn oil Debit	BD production	BD T&D	Total CI	Tank-to-Wheel	LUC	Final CI, g/MJ
	VOC	0.36	0.19		2.40	0.96	3.90			3.90
	CO	1.46	0.62		5.75	3.15	10.98			10.98
	CH4	6.35	1.28		37.07	3.62	48.32			48.32
	N2O	0.06	0.00		0.18	0.03	0.27			0.27
	CO2	2982.07	552.48		11148.76	1619.74	16303.05			16303.05
	Subtotal gCO_2e/MJ	**3.00**	**0.56**	**11.17**	**11.51**	**1.64**	**27.87**	**0.76**	**0.00**	**28.63**
	Adjustment	**2.84**	**0.53**	**10.59**	**10.92**	**1.64**	**26.52**	**0.76**	**0.00**	**27.28**
Aug-18	**Distiller's Corn/Sorghum Oil from DGS of Dry Mill Ethanol to Biodiesel**									
	g/MMBtu	Distiller's oil Extraction	Distiller's Oil Transport	Distiller's oil Debit	BD production	BD T&D	Total CI	Tank-to-Wheel	LUC	Final CI, g/MJ
	VOC	0.36	0.20		2.39	0.96	3.91			3.91
	CO	1.46	0.68		5.73	3.16	11.02			11.02
	CH4	6.34	1.09		37.02	3.32	47.77			47.77
	N2O	0.06	0.00		0.18	0.03	0.27			0.27
	CO2	2980.62	452.10		11124.00	1472.30	16029.02			16029.02
	Subtotal gCO_2e/MJ	**3.00**	**0.46**	**11.26**	**11.49**	**1.49**	**27.69**	**0.76**	**0.00**	**28.45**
	Adjustment	**2.84**	**0.43**	**10.68**	**10.89**	**1.49**	**26.34**	**0.76**	**0.00**	**27.10**

SF31-12
continued from previous page

GROWTH ENERGY'S RESPONSE TO THE "SECOND NOTICE OF PUBLIC AVAILABILITY OF MODIFIED TEXT AND AVAILABILITY OF ADDITIONAL DOCUMENTS AND INFORMATION," DATED AUGUST 13, 2018, AND AUGUST 15, 2018, ERRATA

EXHIBIT "B"

Comments on Second Notice of Public Availability of Modified Text and Availability of Additional Documents and Information and Errata Dated August 13, and August 15, 2018

Prepared by Jim Lyons, Trinity Consultants August 30, 2018

CARB's Proposal to Provide "Capacity" Credits for Electric and Fuel Cell Vehicle Infrastructure is Contrary to the Purpose of the LCFS and Should Not Be Included

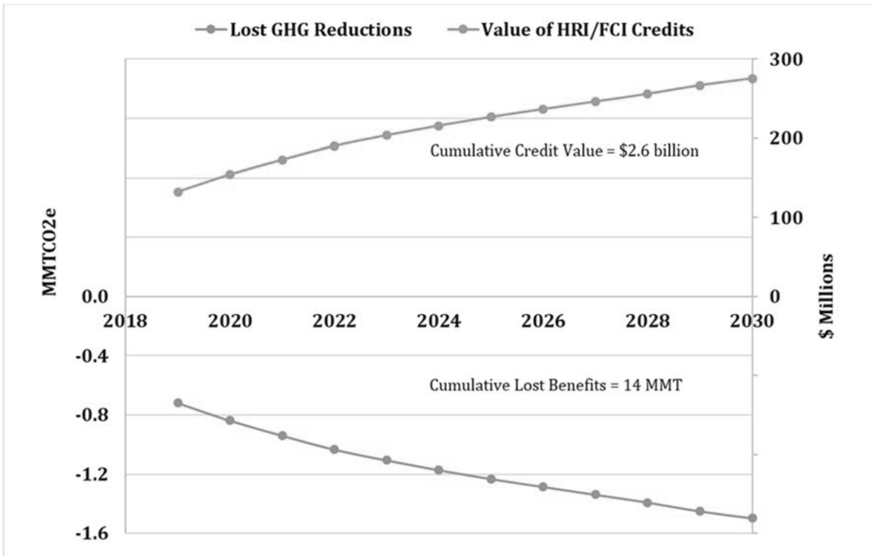
As part of the second 15-day notice, CARB has made a number of modifications to the proposed new section of the low carbon fuel standard regulation ("LCFS"), 95486.2 to Title 17, California Code of Regulations, which is intended to provide LCFS credits to hydrogen stations and direct current (DC) fast charging stations based on the installed capacity to deliver hydrogen and electricity in addition to the LCFS credits provided for the "fuel" that is actually delivered to and used by electric (EV) and fuel-cell (FCV) vehicles. However, none of these proposed changes address the fundamental issues raised by the public and Growth Energy during comments on the first 15-day notice. Rather, Section 95486.2 continues to contemplate that LCFS credits would be provided to owners and operators of DC fast charging and hydrogen stations for not actually selling low-CI fuel, but for the theoretical sales they could have if their stations were utilized to their full capacity. The direct result of this process is a loss in the GHG reductions that would result from the proposed LCFS, and windfall revenue for the station operators.

In order to put the potential magnitude of these issues into perspective, Figure 1 shows the estimated maximum amount of GHG reductions that could be lost due to the implementation of Section 95486.2 and the estimated maximum amount of windfall revenue that owners and operators of DC fast charging and hydrogen stations could realize based on the deficit values projected in the August 15, 2018 version of the Illustrative Compliance Scenario Calculator posted on CARB's website[1] as configured for the "Low Demand" and "Project/LD/Low ZEV/20%/infra" cases. The data in the figure assume that 5% of total deficits each year from 2019 to 2030 are provided as infrastructure credits and that the value of each LCFS credit received is $184 – the average LCFS credit price for Q2, 2018. As shown, the annual amount of GHG reductions that would not be realized by the LCFS program due to the proposed infrastructure crediting provisions would range from about 0.8 to 1.6 $MMTCO_2eq$ per year and the cumulative loss in GHG emissions from 2019 to 2030 could amount to 14.0 $MMTCO_2eq$. Similarly, windfall revenue received by operators and owners of DC fast charge and hydrogen stations could amount to about $150 to $300 million per year with the potential cumulative value being about $2.6 billion. Under CARB's high fuel demand scenarios, lost GHG benefits and windfall revenues would be even greater. It should also be noted that CARB staff acknowledges in Attachment G to the 2nd 15 day notice that accounting for infrastructure credits for hydrogen and DC fast charges is one of the factors that lead to a reduction in the cumulative SF31-14a

[1] See https://www.arb.ca.gov/fuels/lcfs/rulemakingdocs.htm

GHG benefits claimed for the LCFS program from 117 to 97 $MMTCO_2eq$ (a loss of 17%) compared to the current conditions baseline and from 70 to 63 $MMTCO_2eq$ (a loss of 10%) compared to the business-as-usual scenario.

Figure 1. Potential Loss in GHG Reductions and Windfall Revenue Transferred Under CARB's Proposed Infrastructure "Capacity" Program



SF31-14a cont.

In addition to continuing to propose new Section 95486.2, CARB staff has failed to provide any meaningful analysis of the potential environmental impacts associated with the infrastructure crediting provision that were highlighted in comments submitted on the first 15-day notice or any explanation of why the new Section 95486.2 results in the potential reduction in the GHG benefits of the LCFS program. SF31-14b

CARB Has a Viable Alternative to the Proposal to Provide "Capacity" Credits for Electric and Fuel Cell Vehicle Infrastructure that would Achieve the Same Result without Sacrificing GHG Reduction Benefits of the LCFS Program

As part of the second 15-day notice CARB is proposing changes to Title 17, CCR, section 95483(c)(1)(A), which would "*require an opt-in electrical distribution utility (EDU) or its designee, generating base credits for residential EV charging to participate in a statewide point of purchase rebate program funded exclusively by LCFS credit proceeds, if such a program is established.*" SF31-15

The proposed required contribution of all LCFS credits generated from residential EV charging vary depending on the type of EDU. This is shown in Table 1 below, which is

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taken from the draft regulatory text published as part of the Second 15-day notice. Table 1 shows the required contribution for all electrical distribution utility (EDU) types to the point of purchase rebate program is substantially less than 100%.

Table 1. Proposed EDU Contributions of LCFS Credit Proceeds to a Statewide Point of Purchase Rebate Program

EDU category	% Contribution in years 2019 through 2022	% Contribution in years 2023 and subsequent years
Investor-owned Utilities	67%	67%
Large Publicly-owned Utilities	35%	45%
Medium Publicly-owned Utilities	20%	25%
Small Publicly-owned Utilities	0%	2%

In addition, CARB is proposing changes to Title 17, CCR, section 95491(d)(3)(A)2 that concern unmetered residential EV recharging and are intended to *"clarify that an LSE generating credits must use all credit proceeds to benefit the current or future EV drivers across California and not just within its service territory. This would allow opt-in utilities to use base credits proceeds for a statewide point of purchase rebate."* SF31-15 cont.

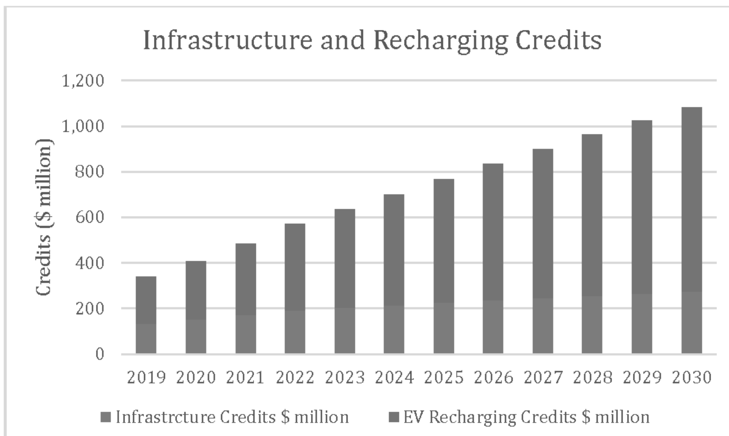
As has been indicated in previous comments, the LCFS credits generated from unmetered residential charging are at best estimates. These credits are not based on actual fuel delivery, as is required for all other fuels under the LCFS. As a result, residential metering or verification of fuel use by other means should be required. While LCFS credits from EV recharging at least have some basis in terms of actual GHG reductions, the LCFS credits CARB is proposing to give to underutilized DC fast charging and hydrogen stations do not result in any such reductions.

As shown above, not all of the value of LCFS credits associated with EV charging are being required to be provided for use in the statewide point of purchase rebate program. Thus, the value of the remaining LCFS credits is based, at least to some degree, on actual reductions in GHG emissions. As such, even if CARB has been directed to provide "capacity" credits for hydrogen and DC fast charging stations "to support the expansions of such infrastructure as directed by Governor's Executive Order B-48-18", as stated on pages 6 and 7 of Appendix F to the first 15-day notice, CARB could use the remaining value of the residential EV charging credits to provide funding for underutilized DC fast charging and hydrogen stations rather than creating fictitious LCFS credits that are not based on actual GHG reductions.

It appears that there should be ample funding available for EV/FCV infrastructure. Figure 2 compares the maximum values of the LCFS credits proposed by CARB staff for infrastructure, to the total value of credits from recharging of light-duty EVs as documented in the August 15, 2018 version of the Illustrative Compliance Scenario Calculator for the "Low Demand" and "Project/LD/Low ZEV/20%/infra" cases. As shown in Figure 2, the magnitude of the value of the infrastructure credits proposed by CARB is small compared to the value of the credits that EDUs receive from residential EV recharging. Although availability of DC fast charging to the extent that such capacity is actually needed could "*benefit the current or future EV drivers across California,*" CARB would simply have to change EV to "Zero Emission Vehicle (ZEV)" to allow for the use of funds from EV recharging to also support hydrogen station infrastructure, which could obviously benefit current or future FCV drivers across California.

SF31-15 cont.

Figure 2. Comparison of Revenue Associated with CARB Proposed Infrastructure Credits with Available Revenue from Recharging of Light-Duty EVs.



Based on the above, CARB should abandon its proposal to create LCFS credits that are not based on actual GHG emission reductions to support DC fast charging and hydrogen stations. Instead, CARB should simply require that the surplus credit value generated by the EDUs beyond those needed for the point of purchase rebate program be used to provide funding for underutilized DC fast charging and hydrogen stations. In addition, CARB should use these surplus funds to promote the development of infrastructure for other low-CI fuels such as E85, as use of E85 in California is dramatically limited by the lack of a widespread distribution and dispensing infrastructure.

CARB Should Decline to Require Verification of all Fuel Provider Pathways, and Should Instead Implement Random Third-Party Verification of a Small Proportion of Pathways

SF31-16

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As has been extensively noted in the public comments, the proposed requirements for verification of fuel producer pathways and annual pathway reports by accredited third parties will impose substantial burdens on producers of low-CI fuels, including ethanol.

First and foremost of these burdens is the cost of paying the verifier for the same work that in-house compliance teams and/or consultancies have already completed, as accredited verifiers will essentially be duplicating work performed as part of LCFS pathway application and reporting purposes. The second is a potential lack of verifiers to choose from given the proposed requirements related to conflicts of interest.

In order to become CARB-accredited, potential verifiers must submit an application to CARB including a self-evaluation of potential conflict of interest (COI) that may exist between them and the fuel provider (e.g. regulated entity or party) that they will be performing verification services for during the "look back period, which is 5 years prior to the start of verification. Any potential COI is also required to be monitored during the year of verification as well as one year after verification services are completed. If "high" conflicts of interest are found to be present, verifiers may be disqualified from providing verification services to specific fuel providers.

The following are some of the services identified in the proposed regulation as posing high potential for conflicts of interest:

SF31-16 cont.

1. Regulated party shares any management staff that have been employed by the verification body or vice versa.
2. Verifier or its company has previously provided the following services:
    - Designing, developing, implementing or maintaining data for CARB's Mandatory Reporting Regulation MRR reporting;
    - Developing CI or fuel transaction data or other GHG engineering analysis;
    - Providing consultative engineering or technical services related to fuel production facility that explicitly identify GHG reductions as a benefit;
    - Conducting internal audit or maintaining a GHG reduction offset project as defined per Cap-and-Trade regulation, or a project to receive LCFS-based credits;
    - Preparing LCFS fuel pathway applications or LCFS reporting manuals;
    - Managing health, environment or safety functions of the entity;
    - Services related to the development of information systems or consulting on the development of environmental management systems except for accounting management systems.
    - Reporting or uploading data on behalf of entity;
    - Owning, buying, selling, trading or retiring LCFS credits;
    - Dealing, brokering or promoting credits on behalf of entity;
    - Appraisal services of GHG liabilities or assets;

- Internal audits related to internal accounting controls or financials;
- Any legal services; and
- Expert services to an entity or its trade group related to litigation or regulatory investigation.

3. The verification body cannot provide any monetary or non-monetary incentives to secure contract.

Based on the above, many qualified companies would not be able to receive CARB verifier accreditation creating an issue for regulated parties as there likely to be a very limited number of verifiers to choose from. Another problem is that the COI requirements make it difficult for large, reputable consulting firms to become accredited verifiers due to their corporate associations. These companies generally provide a large range of environmental consulting services on a disaggregated bases from separately-managed offices and locations.

SF31-16 cont.

Although the second 15-day notice provides some limited relief related to the issue of third-party verification, it does not address the fundamental problems identified above.

As an alternative to the current CARB proposal, Growth Energy strongly suggests eliminating the applicability of verification requirements to all of the subject regulated entities. CARB should instead require random third-party verification of only a small fraction regulated parties; for example, 5% of regulated entities each year. Clearly, having all regulated entities potentially being subject to a random verification will be close to, if not as effective, as mandatory verification in ensuring compliance but will impose a much smaller financial burden on fuel providers.