State of California
Environmental Protection Agency
AIR RESOURCES BOARD

FINAL STATEMENT OF REASONS

AMENDMENTS TO THE LOW CARBON FUEL STANDARD REGULATION

October 2012

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State of California
California Environmental Protection Agency
AIR RESOURCES BOARD

Final Statement of Reasons for Rulemaking,
Including Summary of Public Comments and Agency Responses

PUBLIC HEARING TO CONSIDER AMENDMENTS TO
THE LOW CARBON FUEL STANDARD

Public Hearing Date: December 16, 2011
Agenda Item No.: 11-10-2

I. GENERAL

A. Action Taken in This Rulemaking

In this rulemaking, the Air Resources Board (ARB or the Board) is amending the Low Carbon Fuel Standard (LCFS). The amendments will clarify, streamline, and enhance specific provisions of the regulation, and will build on the comprehensive and extensive work that was done for the original 2009 rulemaking. The overall goal of the LCFS is to reduce greenhouse gas (GHG) emissions by reducing the carbon intensity (C) of transportation fuels used in California by 10 percent by 2020. In addition, the LCFS is designed to reduce California's dependence on petroleum, create a lasting market for clean transportation technology, and stimulate the production and use of low-carbon fuels in California.

The rulemaking was initiated by the October 26, 2011, publication of a notice for a public hearing scheduled on December 15, 2011. A Staff Report: Initial Statement of Reasons, entitled "Proposed Amendments to the Low Carbon Fuel Standard" (Staff Report or ISOR) was also made available for public review and comment starting October 26, 2011. The Staff Report, which is incorporated by reference herein, contains an extensive description of the rationale for the proposal. The proposed text of amended sections 95480.1, 95481, 95482, 95484, 95485, 95486, 95488, and new sections 95480.2, 95480.3, 95480.4, and 95480.5, title 17, California Code of Regulations (CCR), was included as Appendix A of the Staff Report. These documents were also posted on October 26, 2011, on ARB's internet site for this rulemaking at http://www.arb.ca.gov/regact/2011/lcfs2011/lcfs2011.htm.

On November 15, 2011, ARB published a notice to change the date of the public hearing, as it appeared in the 45-day notice, to December 16, 2011.

On December 16, 2011, the Board conducted a public hearing to consider the proposal as set forth in the Staff Report. During the comment period, the Board received a total of 100 written comments and multiple copies of five form letters, totaling

9,222 submittals in all. At the hearing, the Board received 28 oral testimonies and an additional six written submittals.

At the conclusion of the hearing, the Board adopted Resolution 11-39 (Resolution), in which it approved the originally proposed regulation with a number of modifications. These modifications had been suggested by staff in response to public comments made after issuance of the original proposal. The narrative description of each modification was contained in a four-page document entitled “Public Hearing to Consider Proposed Amendments to the Low Carbon Fuel Standard – Staff’s Suggested Modifications to the Original Proposal,” which was distributed at the beginning of the hearing and included as Attachment B to the Resolution.

The Resolution directed the Executive Officer to incorporate the modifications described in Attachment B into the originally proposed regulatory text, with such other conforming modifications as may be appropriate. The Executive Officer was directed to make the modified regulation (with the modifications clearly identified) and any additional documents or information available for a supplemental public comment period of at least 15 days. He was also directed to consider any comments on the modifications received during the supplemental comment period. The Executive Officer was then directed to either (1) adopt the modified regulation as it was made available for public comment, with any appropriate additional non-substantial modifications; (2) make additional modifications available for public comment for an additional period of at least 15 days; or (3) present the regulation to the Board for further consideration if he determines that this is warranted.

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

The text of the proposed modifications to the regulation, with the modified text clearly indicated, was made available for a 15-day comment period ending April 25, 2012, by issuance of a Notice of Public Availability of Modified Text (the First Notice of Modified Text). This notice and its two attachments—Resolution 11-39 with attachments and a “Modified Regulation Order” containing the modified regulatory text—were posted on the ARB rulemaking website and made available for public comment beginning on April 10, 2012. Five written comments were received during the first comment period ending April 25, 2012.

In light of the supplemental comments received during the first 15-day comment period and continuing work, the Executive Officer determined that additional modifications were appropriate. A Second Notice of Public Availability of Modified Text (the Second Notice of Modified Text) and a “Modified Regulation Order” containing the modified regulatory text were posted on the ARB rulemaking website and made available for public comment beginning on made available for public comment on August 9, 2012. The comment period ended August 25, 2012, by which two additional written comments were received.

The Executive Officer initiated a third 15-day comment period specifically to solicit comments on a new model for calculating the carbon intensity of crude oil. In Resolution 11-39, the Board directed the Executive Officer to continue work with interested stakeholders to develop additional calculation methodologies, accounting procedures, or other measures that can further refine the provisions addressing the carbon intensity of petroleum crude oils, blendstocks, intermediates, and finished products either refined in California or imported into the State, and to propose modifications to the Board for further consideration if the Executive Officer determines that this is warranted. Upon completion of the first version the Oil Production Greenhouse Gas Emissions Estimator (OPGEE), the Executive Officer determined that a third 15-day comment period would be appropriate to solicit public review on the OPGEE model and the staff's proposed provisions for that model. Accordingly, a Third Notice of Public Availability of Modified Text and Availability of Additional Documents and Information (the Third Notice of Modified Text) and a "Modified Regulation Order" containing the modified regulatory text were posted on the ARB rulemaking website and made available for public comment beginning on September 17, 2012. In light of comments received during the second 15-day comment period, additional modifications to other provisions in the regulatory text were also included in the Third Notice of Modified Text. The comment period ended October 2, 2012, by which six additional written comments were received.

With respect to each of the three notices of modified text, staff electronically distributed the notices and all attachments on the Internet posting date to all parties identified, per section 44(a), title 1, CCR, in accordance with Government Code section 11340.85. At the same time, the notices and all attachments were sent to parties that have subscribed to ARB's "LCFS," "fuels," "alternative fuels," and "alternative diesel" list serves for notifications pertaining either to rulemaking actions or other information related to motor vehicle fuels. The "LCFS" list serve has approximately 7,700 subscribers, the "fuels" list serve has approximately 6,200 subscribers, the "alternative diesel" list serve has about 6,500 subscribers, and the "alternative fuels" list serve has approximately 2,200 subscribers.

Upon consideration of the comments received, the Executive Officer subsequently issued Executive Order No. R.12-012 on October 10, 2012, adopting the proposed amendments to sections 95480.1, 95481, 95482, 95484, 95485, 95486, 95488, and 95490 and proposed sections 95480.2, 95480.3, 95480.4, and 95480.5, title 17, California Code of Regulations, with modifications described in Section II of this FSOR.

This FSOR updates the Staff Report by identifying and providing the rationale for the modifications made to the originally proposed amendments. The FSOR also contains a summary of the comments received on the proposed amended regulation during the formal regulatory process and ARB's responses to those comments.

B. Incorporation of Materials by Reference

The following documents are incorporated by reference into the regulation:

1. Section 95486(b)(1) incorporates a computer model, Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model version 1.0 (September 2012), including the associated user guide and technical documentation, and identified the ARB website location where these materials are available for download: www.arb.ca.gov/fuels/lcfs/lcfs.htm.
2. Section 95486(b)(1)(A) incorporates three supplemental fuel-pathway supporting documents prepared by ARB's Stationary Source Division. The three supplemental fuel-pathway documents are: (1) "Detailed California-Modified GREET Pathway for California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) from Average Crude Refined in California"; (2) "Detailed California-Modified GREET Pathway for California Reformulated Gasoline (CaRFG)"; and (3) "Detailed California-Modified GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California". These documents were made available on September 12, 2012.
3. Section 95488 incorporates two forms, the Credit Transfer Form (October 28, 2011) and Credit Allocation Form (October 28, 2011), which are intended to facilitate the transfer of credits between regulated parties and the sequential retirement of credits (in the event a unique credit identifier is implemented by the Executive Officer), respectively.

Each instance of incorporation identifies the incorporated document or model by title and date. All the documents and models were made available in the context of this rulemaking in the manner specified in Government Code section 11346.5(b) or 11347.1. The three supplemental fuel-pathway supporting documents are readily available from ARB's internet site and upon request. The two forms were also made available as Appendix G in the Staff Report and also on ARB's internet website. Based on the above reasons, these documents are reasonably available to the affected public from commonly known sources.

These models and documents are referenced and incorporated into the California Code of Regulations because it would be cumbersome, unduly expensive, and otherwise impractical to publish them in their entirety. Existing ARB administrative practice has been to have models, specifications, test procedures, and similar documents incorporated by reference rather than printed in the CCR because these models, specifications and procedures are highly technical and complex. These include "nuts and bolts" engineering protocols and laboratory practices and have a very limited audience. Because ARB has never printed complete test procedures and similar documents in the CCR, the directly affected public is accustomed to the incorporation format used in the regulation. These test procedures and similar documents as a whole are extensive, and it would be both cumbersome and expensive to print these lengthy, technically complex procedures in the CCR for a limited audience. Printing portions of the test procedures and other documents that are incorporated by reference would be unnecessarily confusing to the affected public. It is not technically possible to publish computer models such as OPGEE in the CCR. And, due to their length and limited audiences, it is impractical to publish the three supplemental fuel-pathway supporting documents in the CCR.

C. Fiscal Impacts

The Executive Officer has determined, pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), that this regulatory action will not create costs or savings to any State agency, except as described on page 71 of the Staff Report, or in federal funding to the State, costs or mandate to any local agency or school district whether or not reimbursable by the State pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code.

In developing this regulatory proposal, staff evaluated the potential economic impacts on private persons and businesses. In accordance with Government Code sections 11346.3 and 11346.5(a)(10), the Executive Officer has determined that the proposed amendments should have no impacts on the creation or elimination of jobs within the State of California, no impacts on the creation of new businesses and the elimination of existing businesses within the State of California, and no impacts on the expansion of businesses currently doing business within the State of California. Finally, the Executive Officer has determined that adoption of the regulatory action will not have a significant, statewide adverse economic impact directly affecting business, including the ability of California's businesses to compete with businesses in other states, or on representative private persons. Analysis of the fiscal impacts of this regulatory action is set forth in Chapter VI of the Staff Report.

D. Consideration of Alternatives

A detailed discussion of alternatives to the initial regulatory proposal is provided in chapter VII of the ISOR. Specifically, the Board considered these alternatives, which included taking no action on any of the amended topics, or taking alternative actions on selected topics.

Alternative Options for designating the potential electricity regulated parties:

- Designate electric utilities as potential regulated parties for all EV charging.
- Designate EV owners as potential regulated parties for electricity delivered to their vehicles.
- Omit potential default regulated parties.

Alternative Approaches to Crude Oil Provisions

The Board considered five alternative approaches the crude oil provisions. These include:

1. Current Approach with Amendments
2. Hybrid California Average/Company Specific Approach
3. Company Specific Approach
4. Worldwide Average Approach
5. California Baseline Approach

ARB considered these potential alternative approaches to the regulation and, for the reasons described in the ISOR, found that none was more effective in carrying out the purpose of the regulation, or would be as effective as or less burdensome than the proposed amendments.

II. MODIFICATIONS MADE TO THE ORIGINAL REGULATION

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

A. Summary of First Notice of Public Availability of Modified Text

The first 15-Day Notice was issued April 10, 2012, with an April 25, 2012, deadline. It solicited comment only on the limited number of additional regulatory modifications being made available. The regulatory modifications consisted of:

1. Changes to section 95481 (a) and (b) with added definitions and acronyms. The definition of “on-road,” “electric vehicle (EV),” “battery electric vehicle (BEV),” “hybrid electric vehicle (HEV),” and “plug-in hybrid electric vehicle (PHEV)” were added, and acronyms “EV” and “HEV” were added to the list.

2. Changes to section 95484(a)(6) electricity regulated party provisions to provide a more accurate description of a fleet operator by including specifying any “person” operating a fleet, rather than any “company,” and specify regulated parties for EV battery switch stations to allow a switch-station owner to opt in as a potential regulated party and receive credits.

3. Changes to section 95484(b)(3)(A) quarterly reporting requirements for imported petroleum intermediates, blendstocks, and finished fuel were deleted and added a reporting requirement for marketable crude oil name (MCON) designation, volume (in gal), and Country (or State) of origin for each MCON supplied to the refinery during the quarter.

4. Changes to section 95484(b)(4) annual reporting requirements to include: MCON designation, volume (in gal), and Country (or State) of origin for each MCON supplied to the refinery during the annual compliance period.
    a. For each MCON, the constituent field names and the percentage of the MCON supplied from each field. For each MCON that includes a non-crude diluent, the type of diluent (e.g. natural gas condensate, naphtha, etc.) and the percentage of diluent in the MCON.
    b. For each field listed in 1.a.,the total annual volume produced by the field, the percentage produced using thermally enhanced oil recovery (TEOR), the percentage produced using oil sands mining, and the percentage that is upgraded to synthetic crude oil.

5. Changes to section 95485(a)(1) Table 4 Energy Densities of LCFS Fuels and Blendstocks to provide a more accurate value for ethanol. The energy density value for denatured ethanol was used to replace the original value shown for

anhydrous ethanol because gasoline and similar fuels use denatured ethanol rather than anhydrous ethanol.

6. Changes to section 95486(f) to maintain the transparency and improve the Method 2A/2B certification process with a public comment period prior to the Executive Officer taking final action on certification applications.

7. Changes to section 95486(b)(1) Tables 6 and 7 to incorporate new and modified fuel pathways adopted as a result of the February 2011 Executive Officer hearing.

8. Changes to section 95486(b)(2)(A) to delete the requirement that "Crude oil used to produce CARBOB or diesel for which a credit is claimed in a calendar year pursuant to section 95486(b)(2)(A)3 will be included in the Annual Crude Average CI calculations for that year based on the CI of the crude oil prior to calculation of any innovative credits allowed pursuant to section 95486(b)(2)(A)3. Staff included language that specifies that the Annual Crude Average CI will be calculated using a three year rolling average of crude oil supplied to California refineries. The three-year rolling average will be phased in and will completely in place three years after the start of the new provisions.

9. Changes to section 95488(c)(3) to clarify the option for blind trading under the program. Staff specified that a credit facilitator may conduct a "blind transaction," where the buyer's and seller's identifies are not disclosed to each other at the time of the transaction.

B. Summary of Second Notice of Public Availability of Modified Text

The Second 15-Day Notice was issued August 9, 2012 with an August 24, 2012 deadline. It solicited comment only on the limited number of additional regulatory modifications being made available. The regulatory modifications consisted of:

1. Changes to section 95481 to the definitions of "producer" and "production facility" to further clarify who would be considered an out-of-state producer by specifying that one must opt into the program under section 95480.3 in order to be considered an out-of-state producer.

2. Changes to section 95484(b)(4)(B) with deletions of certain field-specific reporting requirements for producers of CARBOB, gasoline, or diesel fuel.

3. Changes to section 95486(b)(1) to clarify that the Executive Officer may approve the use of a model other than CA-GREET to generate carbon intensity value, if the Executive Officer determines the model is equivalent to CA-GREET, version 1.8b.

4. Changes to section 95486(c) Modified Method 1 (Method 2A) provisions to clarify that the Executive Officer may approve the use of a model other than CA-GREET to generate carbon intensity value, if the Executive Officer determines the other model is equivalent to CA-GREET, version 1.8b.

5. Changes to section 95486(d) to clarify that the Executive Officer may approve the use of a model other than CA-GREET to generate carbon intensity value, if the Executive Officer determines the other model is equivalent to CA-GREET, version 1.8b.

6. Changes to section 95486(f)(3)(C) pathway application requirements to clarify that when preparing the life cycle analysis of a proposed fuel pathway, applicants must use CA-GREET or a method approved by the Executive Officer as equivalent to CA-GREET.

C. Summary of Third Notice of Public Availability of Modified Text

The Third 15-Day Notice was issued September 17, 2012, with an October 2, 2012, deadline. It solicited comment only on the limited number of additional regulatory modifications being made available. The following is a summary of the proposed substantive modifications to the regulation and staff's rationale for making them. All references to sections refer to title 17, CCR, unless otherwise noted. The following list does not include modifications to correct typographical and citation errors, numbering errors, grammar errors, or the rearranging of sections and paragraphs for structural improvements, nor does it include minor revisions made to improve clarity or other nonsubstantive modifications.

1. Changes to section 95480.3 to clarify the information required to be submitted to ARB in order to opt-in to the LCFS program, the process for a party that opts-in to the LCFS program to select a carbon intensity value, and that the LCFS recordkeeping requirements applicable to regulated parties will apply to parties that opt-in to the LCFS.

2. Changes to section 95480.5 related to jurisdiction. Staff added any submittal of documentation pursuant to the crude oil innovative method provision to actions that establish a person's consent to be subject to the jurisdiction of the State.

3. Changes to section 95481 to add a definition for "day" to mean calendar day unless otherwise specified.

4. Changes to definitions of "Aggregation Indicator," "Biofuel Production Facility," "Business Partner," "Physical Pathway Code," "Production Facility," "Transaction Date," "Transaction Quantity," "Transaction Type" in section 95481(a)(1), (8), (15), (47), (51), (56), (57), (58), respectively, to remove reference to the LRT.

5. Changes to the definition of "On Road," in section 95481(a)(45), for clarity.

6. Changes to section 95481(a)(40) to clarify definition of reporting deadlines. Staff clarified the definition of “LRT Reporting Deadlines” by referencing the quarterly and annual reporting dates specified in section 95484(b)(1).

7. Changes to section 95482(b) and (c) to revise the compliance schedules. Staff revised the LCFS compliance schedules with updated average carbon intensity requirements for gasoline and diesel fuel. The average carbon intensity requirements for years 2013 to 2020 reflect reductions from revised base year 2010 carbon intensity values for California reformulated gasoline (CaRFG) and ultralow-sulfur diesel (ULSD).

8. Changes to section 95484(b)(3)(A)4 to revise reporting requirements. Staff revised the quarterly and annual reporting requirements to accommodate situations when crude is supplied to a refinery without a Marketable Crude Oil Name (MCON). Slight revisions were made to further clarify what producers of California reformulated gasoline blendstock for oxygenate blending (CARBOB), gasoline, or diesel must report for each of its refineries.

9. Changes to section 95486 revising Table 3. Staff revised the *Summary Checklist of Quarterly and Annual Report Requirements* (Table 3) to be consistent with revisions made to the reporting requirement for gasoline and diesel.

10. Modifications to section 95486(a)(4) to clarify when a carbon intensity value is defined as “unable to be determined.”

11. Changes to section 95486 to incorporate the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model (version 1.0). Staff added the model information to clarify the specific model, or equivalent model, to be used for the generation of carbon intensity values for crude oil production and transport to California refineries. The OPGEE model version 1.0 is incorporated in the regulation by reference.

12. Changes to section 95486(b)(1) to update fuel pathway supplements. Staff updated the fuel pathway supplements for CARBOB, CaRFG, and ULSD (supplement version 2.0, dated September 12, 2012).

13. Changes to section 95486(b)(1) to add crude carbon intensity values to a new table. Staff added individual crude carbon intensity values in separate Table 8, and revised Tables 6 and 7 Carbon Intensity Lookup Tables for gasoline, diesel and their substitutes with updated 2010 CARBOB, ULSD, and baseline crude average carbon intensity values for each fuel.

14. Changes to section 95486(b)(2)(A)1 updating the baseline carbon intensity values to a 2010 baseline. Staff updated CARBOB, ULSD, and Baseline Crude Average carbon intensity values to reflect a 2010 Baseline. The 2009 baseline

calendar year referenced in CARBOB and diesel fuel deficit calculations were updated to 2010.

15. Changes to section 95486(b)(2)(A) to include an application process for innovative crude production methods. Staff proposed modifications to specify the process for a crude oil producer to apply for approval of innovative crude production methods. A regulated party or oil producer would need to obtain approval of the innovative crude oil production method before a regulated party can receive credit under the LCFS regulation for use of that crude oil production method.

16. Changes to section 95486(f)(3)(C) to clarify Method 2A/2B pathway application requirements. Staff proposed language to clarify the information that would be required to be submitted in the Method 2A/2B application form and made modifications to other application requirements, including format for citations and references.

17. Changes to section 95486(f)(3)(D) to specify when a Method 2A/2B application is determined to be complete. Staff proposed revisions to clarify the process that will be used to determine if a Method 2A/2B application is complete and the process for a party to submit additional information, if needed.

18. Changes to section 95486(f)(3)(E) to clarify public comment procedures for Method 2A/2B. Staff proposed modifications to specify the process for submission of public comments on Method 2A/2B applications and the applicant's opportunity to respond to any public comments on Method 2A/2B applications.

19. Changes to Section 95486(f)(3)(F) to specify date on which Method 2A/2B evaluation would begin. Staff proposed modifications to clarify the time period for evaluation of a Method 2A/2B application, including the date on which evaluation would begin.

20. Changes to section 95486(f)(3)(H) to specify that Method 2A/2B applications that are denied without prejudice may be resubmitted.

21. Changes to section 95486(f)(3)(I) clarifying evaluation criteria for Method 2A/2B applications. Staff proposed amendments to clarify the criteria against which Method 2A/2B applications would be evaluated.

22. Changes to section 95486(f)(3)(L) to specify the recordkeeping requirements for approved Method 2A/2B applications, including that records required to be retained must be submitted to the Executive Officer within 20 days of a written request.

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

This section contains a summary of each comment that: (1) was submitted at the hearing or during the 45-day comment period; and (2) was specifically directed at the proposed amendments to the regulation or to the procedures followed by ARB in proposing or adopting amendments, together with ARB's responses. Comments not involving objections or recommendations specifically directed towards the regulation or procedures followed are generally not summarized. These include comments supporting the LCFS proposal and the purpose of the program.

A. List of Commenters

The table below identifies the comments received during the 45-day comment period that presented an objection or recommendation specifically directed toward the regulation or the procedures followed.

The table provides a correlation between: (1) the abbreviation used in this section to refer to a comment letter or testimony; and (2) the name of the person(s) signing the comment letter or presenting the testimony. Written submittals were received between October 26, 2011, and December 16, 2011. Oral testimony was presented at the December 16, 2011, hearing.

Abbreviation	Commenter
FORMLETTER1	Laura Lynch, Natural Resources Defense Council **771 additional commenters submitted similar comments** Written Testimony: November 8, 2011
ECOTALITY1	Jason Wolf, Better Place; Don Karner, ECOtality North America; Richard Lowenthal, Coulomb Technologies, Inc. Written Testimony: November 2, 2011
KEITH	Jeanne Keith-Ferris Written Testimony: November 17, 2011
SCOTT	Sierra Scott Written Testimony: November 28, 2011
SCPPA1	Lily Mitchell* and Norman A. Pedersen, Esq., attorney for the Southern California Public Power Authority Written Testimony: December 2, 2011
FORMLETTER2	Mark Weinberger, American Lung Association in California **671 additional commenters submitted similar comments** Written Testimony: December 5, 2011
OSD	Clark Nakamura, Oil Supply and Distribution Written Testimony: December 8, 2011

CMUA1	Tony Andreoni, California Municipal Utilities Association Written Testimony: December 8, 2011
NRDC1	Max Baumhefner, Simon Mui and Debbie Hammel, Natural Resources Defense Council Written Testimony: December 8, 2011
SOBEL	Heywood Sobel Written Testimony: December 10, 2011
NIXON	Jim Nixon Written Testimony: December 10, 2011
WEIKART	Scott Weikart Written Testimony: December 10, 2011
COX	Joseph S. Cox Written Testimony: December 10, 2011
MCLEOD	Donald McLeod Written Testimony: December 10, 2011
COHEN	Dr. Richard Cohen Written Testimony: December 10, 2011
WALP	Susan Walp Written Testimony: December 10, 2011
VAJ	Marcy Vaj Written Testimony: December 10, 2011
WESTBROOK	Janet Westbrook Written Testimony: December 10, 2011
HECKMAIER	Rainier Heckmaier Written Testimony: December 10, 2011
REEVE	Diane C. Reeve Written Testimony: December 10, 2011
MCRAE	Ellen McRae Written Testimony: December 10, 2011
HEIN	Mark Hein Written Testimony: December 10, 2011
ACKERMAN	Bruce Ackerman Written Testimony: December 10, 2011
SPARKS	Fritz Sparks Written Testimony: December 10, 2011
PIRCH	Charlotte Pirch Written Testimony: December 10, 2011
ESTRUP	Carole Estrup Written Testimony: December 10, 2011
VANTHIEL	Mathias van Thiel Written Testimony: December 10, 2011

NAKADEGAWA	Roy Nakadegawa Written Testimony: December 10, 2011
FRANCISCO	Alan Francisco Written Testimony: December 11, 2011
NRDC2	Max Baumhefner and Simon Mui, Natural Resources Defense Council Written Testimony: December 11, 2011
ROON	Brad Roon Written Testimony: December 12, 2011
AAM	Valerie Ughetta, Alliance of Automobile Manufacturers Written Testimony: December 12, 2011
NRC	Douglas Heath* and Mark Corey, Natural Resources Canada; Jennifer Steber, Alberta Energy Written Testimony: December 9, 2011
FORMLETTER3	Trudi Reinhardt, California League of Conservation Voters **4949 additional commenters submitted similar comments** Written Testimony: December 12, 2011
NRDC3	Simon Mui and Elizabeth Landeros, Natural Resources Defense Council Written Testimony: December 12, 2011
MORRIS	Doug Morris Written Testimony: December 12, 2011
ABCC	Edwin Lombard, Advocate Black Chambers of Commerce Written Testimony: December 12, 2011
SCEC	Nancy Chung Allred and Jennifer Tsao Shigekawa, attorneys for Southern California Edison Company Written Testimony: December 12, 2011
STEIN	Nancy Stein Written Testimony: December 12, 2011
PETTIGREW	Sophie Beth Pettigrew Written Testimony: December 12, 2011
WSPA1	Catherine H. Reheis-Boyd, Western States Petroleum Association Written Testimony: December 2, 2011
Comment Removed	
BOELLSTORFF	Tom Boellstorff Written Testimony: December 13, 2011
COHENRON	Ronald Cohen Written Testimony: December 13, 2011
STOCK	Linda Stock Written Testimony: December 13, 2011

SFPUC	Meg Meal, Jeremy Waen and Barbara Hale, San Francisco Public Utilities Commission Written Testimony: December 13, 2011
WILHOIT	Betty Jane Wilhoit Written Testimony: December 13, 2011
NEARGARDER	Patrick Neargarder Written Testimony: December 13, 2011
GOFF	Frances Goff Written Testimony: December 13, 2011
ROBINSON	Terry Ellen Robinson Written Testimony: December 13, 2011

ALA1	Jamie Knapp*; May Boeve, 350.0rg; Bonnie Holmes-Gen, American Lung Association in California; Andy Katz, Breathe California; Susan Hogeland, California Academy of Family Physicians; Susan Jordan, California Coastal Protection Network; Rev. Canon Sally Bingham, California Interfaith Power & Light; Warner Chabot, California League of Conservation Voters; Nick Lapis, Californians Against Waste; Betsy Reifsnider, Catholic Charities, Diocese of Stockton; John Shears, Center for Energy Efficiency and Renewable Technologies; Christina Tirado, Center for Public Health and Climate Change; Kevin Hall, Central Valley Air Quality Coalition; Jan Jarrett, Citizens for Pennsylvania's Future; V. John White, Clean Power Campaign; Ann Hancock, Climate Protection Campaign; Nidia Bautista, Coalition for Clean Air; N. Jonathan Peress, Conservation Law Foundation; Anne Pernick, Corporate Ethics International; Jeremy McDiarmid, Environment Northeast; Remy Gerderet, Energy Independence Now; Daniel Gatti, Environment America; Bernadette Del Chairo, Environment California Research & Policy Center; Tim O'Conner, Environmental Defense Fund; Ziva Gobbo, Focus Association for Sustainable Development, Slovenia; Michael Noble, Fresh Energy; Darek Urbaniak, Friends of the Earth, Europe; Debra Judelson, Los Angeles County Medical Association Air Quality Committee; Beth Pratt, National Wildlife Federation; Jana Gastellum, Oregon Environmental Council; Anne Lamb, Regional Asthma Management & Prevention; Sue Malone, San Mateo County Medical Association; Kathryn Phillips, Sierra Club California; Gary Lasky, Sierra Club Tehipite Chapter; Michelle Passero, The Nature Conservancy; Ann C. Chan, The Wilderness Society; Stuart Cohen, TransForm; Nusa Urbancic, Transport & Environment; Marylia Kelley, Tri-Valley CAREs; Suzanne Dhaliwal, UK Tar Sands Network; Jeremy I. Martin, Union of Concerned Scientists Written Testimony: December 14, 2011
WYATT	Ashley Wyatt Written Testimony: December 14, 2011
NORRIS	Manly Norris Written Testimony: December 14, 2011
CIOMA	Jay McKeeman, CIOMA Board of Directors and CIOMA Membership, California Independent Oil Marketers Association Written Testimony: December 14, 2011

BP1	Ralph J. Moran, BP America, Inc. Written Testimony: December 8, 2011
VOEGE	Hal Voege Written Testimony: December 14, 2011
RR	Tom Faust, Redwood Renewables Written Testimony: December 14, 2011
FC	Robert M. Sturtz, Fueling California Written Testimony: December 14, 2011
FORMLETTER4	Michael Whatley, Consumer Energy Alliance **63 additional commenters submitted similar comments** Written Testimony: December 9, 2011
FORMLETTER5	Annie Pham, Sierra Club California **2662 additional commenters submitted similar comments** Written Testimony: December 8, 2011
RFA	Geoff Cooper* and Bob Dinneen, Renewable Fuels Association Written Testimony: December 14, 2011
PSPC	Harvey Eder, Public Solar Power Coalition Written Testimony: December 14, 2011
ATWATER	David Atwater Written Testimony: December 14, 2011
SOC	John Browning, Silvas Oil Company Written Testimony: December 14, 2011
E2CF	Mary Solecki, E2 Clean Fuels; Dan Adler, California Clean Energy Fund; Stephanie Batchelor, Biotechnology Industry Organization; Eric Bowen, Renewable Energy Group; Harrison F. Dillon, Solazyme; Ed Dineed, LS9; Riggs Eckelberry, OriginOil; Bob Epstein and Mary Solecki, Environmental Entrepreneurs; Brian Foody, Iogen Corporation; Erin McAfee, Aemetis, Inc.; Christopher J. Hessler, AJW, Inc.; Matt Horton, Propel Fuels; Jack Huttner, Gevo; Vinod Khosla and David Mann, Khosla Ventures; Neil Koehler, Pacific Ethanol; Ted Kniesche, Fulcrum BioEnergy, Inc.; Andrew J. Littlefair, Clean Energy; Jeffrey A. Martin, Yulex Corporation; Michael J. McAbrams, Advanced Biofuels Association; Jack Oswald, SynGest Inc., AliphaJet Inc., Optinol Inc.; John Plaza, Imperium Renewables; Brook Porter, Kleiner Perkins Caufield & Byers; Juergen Puetter, Blue Fuel Energy Corporation; Joe Regnery, ZeaChem; Lyle Schlyer, Calgren Renewable Fuels; Paul Zorner, Finistere Ventures Written Testimony: December 14, 2011

SHIPLEY	John Shipley Written Testimony: December 14, 2011
ALA2	Jenny Bard* and Bonnie Holmes-Gen, American Lung Association in California; Robert Vinetz and Anne Farrell Sheffer, Asthma Coalition of Los Angeles County; Jeanne Rizzo, Breast Cancer Fund; Susan Hogeland, California Academy of Family Physicians; Ruben Cantu, California Pan-Ethnic Health Network; Karl Van Gundy, California Thoracic Society; Rachelle Wenger, Catholic Healthcare West; Charlotte Dickson, HEAL Cities Campaign, CA Center for Public Health Advocacy; Jessica Tovar, Long Beach Alliance for Children with Asthma; Debra Judelson, Los Angeles County Medical Association; Kevin D. Hamilton, Medical Advocates for Healthy Air; Ricky Y. Choi, National Physicians Alliance, California; Mary Pittman, Public Health Institute; Robert Gould, SF Bay Area Physicians for Social Responsibility; Harry Wang, Physicians for Social Responsibility/Sacramento; Jeremy Cantor, Prevention Institute; Robert S. Ogilvie; Public Health Law & Policy; Anne Kelsey-Lamb, Regional Asthma Management and Prevention; Michael Kelly, San Diego Regional Asthma Coalition; Steve Heilig, San Francisco Medical Society; Sue Malone, San Mateo County Medical Association; Gloria Thornton, San Francisco Asthma Task Force; Michelle House, Sonoma County Asthma Coalition; Rita Scardaci, Sonoma County Department of Health Services Written Testimony: December 14, 2011

COALITION	Shelly Sullivan*; California Manufacturers and Technology Association; California Chamber of Commerce; California Taxpayers Association; AB 32 Implementation Group; National Federation of Independent Business/CA; Howard Jarvis Taxpayers Association; California League of Food Processors; California Small Business Alliance; California Forestry Association; California Construction Trucking Association; California Concrete Pumpers Alliance; California Independent Oil Marketers Association; Western States Petroleum Association; California Hispanic Chambers of Commerce; American GI Forum of California; American GI Forum Women of California; California Independent Petroleum Association; Kern County Taxpayers Association; Small Business Action Committee; San Diego Tax Fighters; Santa Barbara County Taxpayers Association; Santa Barbara Industry & Technology Association; Coalition of Energy Users; Black Business Association; Carson Black Chamber of Commerce; Kern County Black Chamber of Commerce; Antelope Valley Black Chamber of Commerce; Moreno Valley Black Chamber of Commerce; Long Beach Black Chamber of Commerce; Orange County Business Council; Contra Costa County Taxpayers Association; Los Angeles County Business Federation; Independent Oil Producers Agency; South Bay Latino Chamber of Commerce; Hispanic Chamber of Commerce Silicon Valley; Harbor Trucking Association; Los Angeles Metropolitan Hispanic Chamber of Commerce; Hispanic Chamber of Commerce Contra Costa County; Antelope Valley Hispanic Chamber of Commerce; California Black Chamber of Commerce Written Testimony: December 14, 2011
HNEWTON	H. Newton Written Testimony: December 14, 2011
CIPL	Betsy Reifsnider, California Interfaith Power and Light Written Testimony: December 14, 2011
BIO	Stephanie Batchelor, Biotechnology Industry Organization; ABI; Allylix, Inc.; Amyris Biotechnology, Inc.; Aurora Biofuels; BD Biosciences; BioCatalytics, Inc; Cellana; ChemDiv, Inc; Chevron Corporation; Cobalt Technologies; Codexis, Inc; Danisco; Delphi Ventures; DNA 2.0; Dow; DSM; DuPont; Genencor®; Genomatica, Inc.; LiveFuels, Inc.; LS9; Mendel Biotechnology, Inc; Novozymes; Sapphire Energy; Senomyx, Inc.; Sequesco; Synthetic Genomics; Verdezyne Inc; Verdia, Inc; Verenium; Solazyme, Inc. Written Testimony: December 16, 2011

MEYER	Robert Meyer Written Testimony: December 14, 2011
COFFEY	William Coffey Written Testimony: December 14, 2011
SDG&E1	Alex Kim, San Diego Gas & Electric Written Testimony: December 14, 2011
PIA	Jay Friedland, Plug In America Written Testimony: December 14, 2011
NOVOZYMES	Amy Ehlers, Novozymes Written Testimony: December 16, 2011
CNAES	Kurt E. Blase and Thomas Corcoran, Center for North American Energy Security Written Testimony: December 15, 2011
BICEP	Carol Lee Rawn*, Ceres on behalf of Anne Kelly, Business in Favor of Climate and Energy Policy (BICEP); BICEP members include Anvil Knitwear; Aspen Skiing Company; Avon Products; Ben & Jerry's; Clif Bar & Company; eBay; Eileen Fisher; Gap, Inc.; Jones Lang LaSalle; Levi Strauss & Co.; New Belguim Brewing; Nike; The North Face; Outdoor Industry Association; Portland Trail Blazers; Seventh Generation; Starbucks; Stonyfield Farms; Symantec; Timberland Written Testimony: December 15, 2011
EDLA	Jim Stewart, Earth Day Los Angeles Written Testimony: December 15, 2011
CONOCO1	H. Daniel Sinks, ConocoPhillips Written Testimony: December 15, 2011
RPB	Sam Leavitt*; James Levine, P.E., R Power Biofuels Written Testimony: December 15, 2011
ECOTALITY2	Don Karner, ECOtality; Jason Wolf, Better Place; Richard Lowenthal, Coulomb Technologies, Inc. (same as #2) Written Testimony: December 15 (November 2), 2011

INCR	Carol Lee Rawn*, Ceres on behalf of Investor Network on Climate Risk; Timonthy Smith, Walden Asset Management; Bennett Freeman, Calvert Investment Management, Inc.; Ian Simm, Impax Asset Management Limited; Steven Heim, Boston Common Asset Management, LLC; Julie Fox Forte, Ph.D.; PaxWorld Management LLC; Richard S. Bookbinder; TerraVerde Capital Management LLC; Kristina Curtis, Green Century Capital Management; Susan Vickers, Catholic Healthcare West; Stephen Viederman, Christopher Reynolds Foundation; Shelley Alpern, Trillium Asset Management, LLC; Andy Behar, As you Sow; Sister Patricia A. Daly, Tri-State Coalition for Responsible Investment; Mark Cirilli, MissionPoint Capital Partners; Sister Patricia A. Daly, The Sisters of St. Dominic of Caldwell, NJ; Matthew Fitzmaurice, AWJ Capital Partners, LLC Written Testimony: December 15, 2011
KORC1	Melinda Hicks, Kern Oil & Refining Co. Written Testimony: December 15, 2011
FORMLETTER6	Bill Haskins, Center for Biological Diversity *5041 additional commenters submitted similar comments** Written Testimony: December 15, 2011
WSPA2	Cathy Reheis-Boyd, Western States Petroleum Association Written Testimony: December 15, 2011
PPC	June Christman* and Steven Farkas, Paramount Petroleum Corporation Written Testimony: December 15, 2011
SHELL	John Reese, Shell Oil Products US Written Testimony: December 15, 2011
CBD	Brian Nowicki, Center for Biological Diversity Written Testimony: December 15, 2011
PADULA	Alfred Padula Written Testimony: December 15, 2011
SBM	David Chase* and John Arensmeyer, Small Business Majority Written Testimony: December 15, 2011
CE	Todd Campbell, Clean Energy Written Testimony: December 15, 2011
AEC	R. Brooke Coleman, Advanced Ethanol Council Written Testimony: December 15, 2011
RCP	Jeremy Bautista, River City Petroleum Written Testimony: December 15, 2011

CALETC1	Eileen Tutt, California Electric Transportation Coalition Written Testimony: December 12, 2011
CAPP	Kim Folkins* and Greg Stringham, Canadian Association of Petroleum Producers Written Testimony: December 15, 2011
POTASH	Roger Potash Written Testimony: December 28, 2011
CROSSER	Tom Crosser Written Testimony: December 28, 2011
CA	David Calvo, Calvo Associates Written Testimony: December 28, 2011
MARTINEZ	Emmanuel Martinez Written Testimony: December 28, 2011
CGC2	Cassie Doyle, Consul General of Canada Oral Testimony: December 16, 2011
SDG&E2	Alex Kim, San Diego Gas and Electric Oral Testimony: December 16, 2011
ECOTALITY3	Don Karner, ECOtality Oral Testimony: December 16, 2011
PG&E	Valerie Winn, Pacific Gas and Electric Company Oral Testimony: December 16, 2011
CMUA2	Tony Andreoni, California Municipal Utilities Association Oral Testimony: December 16, 2011
BIODICO	Russell Teall, Biodico Oral Testimony: December 16, 2011
NRDC5	Roland Hwang, Natural Resources Defense Council Oral Testimony: December 16, 2011
CPUC	Adam Langton, California Public Utilities Commission Oral Testimony: December 16, 2011
SMUD	Bill Boyce, Sacramento Municipal Utilities District Oral Testimony: December 16, 2011
CIPA2	Norm Plotkin, California Independent Petroleum Association Oral Testimony: December 16, 2011
CEU2	Eric Eisenhammer, Coalition of Energy Users Oral Testimony: December 16, 2011
TESORO	Dan Romasko, Tesoro Corporation Oral Testimony: December 16, 2011
ALA2	Bonnie Holmes-Gen, American Lung Association of California Oral Testimony: December 16, 2011

CONOCO2	Chris Chandler, ConocoPhillips Los Angeles Refinery Oral Testimony: December 16, 2011
BGA1	Lisa Hoyos, BlueGreen Alliance; Rick Latham, United Steel Workers; Simon Mui, Natural Resources Defense Council Written Testimony: December 15, 2011
BGA2	Lisa Hoyos, Blue Green Alliance Oral Testimony: December 16, 2011
BGA3	Ms. Houston, Blue Green Alliance Oral Testimony: December 16, 2011
ICCT	Chris Malins, International Council on Clean Transportation Oral Testimony: December 16, 2011
KORC2	Jon Costantino, Kern Oil Refining Co. Oral Testimony: December 16, 2011
SCE	Frank Harris, Southern California Edison Oral Testimony: December 16, 2011
CEERT	John Shears, Center for Energy Efficiency and Renewable Technologies Oral Testimony: December 16, 2011
WSPA3	Cathy Reheis-Boyd, Western States Petroleum Association Oral Testimony: December 16, 2011
NRDC4	Simon Mui, Natural Defense Council Oral Testimony: December 16, 2011
BP2	Ralph Moran, BP America Oral Testimony: December 16, 2011
CLARK	Paul Clark Oral Testimony: December 16, 2011
VALERO	John Braeutigam, Valero Oral Testimony: December 16, 2011
CALETC2	Eileen Tutt, California Electric Transportation Coalition Oral Testimony: December 16, 2011
SCPPA2	Norman Pederson, Southern California Public Power Authority Oral Testimony: December 16, 2011
WEAVER	Ron Chapman, Weaver, LLC Written Testimony: December 16, 2011
CGC1	Cassie Doyle, Consulate General of Canada Written Testimony: December 16, 2011

FORMLETTER7	Chris Carney, Union of Concerned Scientists **363 additional commenters submitted similar comments** Written Testimony: December 16, 2011
CIPA1	Norm Plotkin, California Independent Petroleum Association Written Testimony: December 16, 2011
CEU1	Eric Eisenhammer*, Coalition of Energy Users; Dominic Ceballos; Shawna Rogers; Paulette Evans; Vinola Swindell; Nathaniel Johnson, Eric W. Harrys; Tyonka Ware; Christina Hubbard; Bernice Espinoza; Karen Deal; Drake Williams Sr.; Jiy'Vonne Heriveaux; Michelle Edmond; Jetaine Cooper; Della Reese Jenkins; Daniel Johnson; Roger Stephenson; Leonard Alexman; Cathy Nign; Tom Asbury; Wendell Wettstein; Craig Ephraim; Bruce Halligan; Page Nicholson; Jorge Chavez; Michael Fry; Matt Campbell; Gloria R. Vasquez; Coleen Griffen; Martin J Vasquez Jr; Mike Smith; C Jones; Chad Macke; Victor Tapia; Don Stout; Mauro Dentino; Eddy Branes; Jen Koviak; Donald Payne; Mazen Elkhoury; Marcia Hanff; Chris Drake; Rebecca Harris; Tracy Hartman; Gregory Forystek; Dawn Bellante; Steven Marsh; Martin Knowles; Rosa Barraza; Doug Chang; Peter Allen; Tanya Fleenor; Bruce Rhoads; Jerome Liess; Madysn Hanley; Debra Leiss; Ryan Smith; Holly Lucas; Valerie Lee; Shaun Evans; Nikolas Paris; Joseph Lee; Eric Prado; Laura Borys; Jimmy Kondo; Jana Alexander Blaszak; Jeremy Chasey; Michael Duryea; David Ashley; Anthony Perez; Stacy Holt; Sandra Perez; Nick Holt; Shelli Andreski; Charles Christ; Charles Jasper; Andrea Ugalde; Jeremy Akers; Cassie Ardito; Richard Ardito; Sally Campbell; Kathryn Klumpe; Katharina Radford; David Michael Fenolio; Sue Clark; Chuck Williams; Jon Errek; Lydia Thompson-Patriot; Charles A Ransier; Ernie Peterson; Janet Pettigrew; Gary McCabe; Martin Oberle; Kathleen Khosravi; Janice Carroll; William B Threlkel II; Richard Weaver; Jim Turner; Steve Segoria; Lynn Hinrichs; Gary Kelsey; Lesley J. Southard; Betty Ramelli; Patsy Bratta; Mark Rudolph; Ron Rudolph; Sharon Rudolph; Carol Wilson; Marie Brown; Norman Cotton; Michael Goodner; Tim Leslie; Dave Clewett; Kathleen Boyd; Allen Appell; Robert Scaletti; Wes Davis; Tyanne Peters; Mona Aparicio; Charles Koenig; Gerald Bogart; James Galloway; Kevin Kampschmidt; Nancy Williams; Carol Pascoe; Mark Wright; Scott Salee; Theodore Scibek; Marc Nichols; Edwin Simpson; Leslie Nacanisi; Charley Washburn;

	Judith Judson-Baker; Sally Green; Leonard Carter; Randall Jordan; Herb Tuttle; Clyde Lagomarsino; Daniel Woods; David Swift; John Cooper; Robert Eberle; Debbie McFadyen; Harold Kandel; Joslynn Chavannes; Diane Leverich; Larry Nemetz; Vicki Weiser; Ron Weiser; Paul Swanson; Jerry Liffick; John and Barbara Pattillo; Fred Amerson; Theresa Caruso; Glenn Rippee; Edward Veek; Shaun McFadyen; Leanne Gardner; Robert K. Neppel; Karen Lewis; Richard Contratto; Josefina; Calvin Lamb; Winifred L. Baker; Judy Garner; Sue Spillman; Lawrence Dumm; Randi Briggs; Mitch Mills; Warren Weaver; Donna Sanders; Deedee E. Dellos; Christopher Tatasciore; William F. Sommers; James Seif; William T. Royston; John Harms; Gaylene and Kevin Collins; Jean Hedin; Sandra Pelletier; Jose Barragan; Lynn/Don Amo; Sherry Oppenheim; Sara Koehler; Michael Ferriera; Carolyn Payne; Thomas Kelley; James Freeman; Juanita Bonhorst; Sandra H. Harris; Lawrence Crane; Gabriel Wise; Mary Jo Wood; Colleen Britton; Andrew Arnold; Les Noriel; Mary Kimura; Peter Kazak; Carol Edon; Dwight Graef; Sue Kleiman; Paul Martinelli; Anita Cecil; Phillip Boso; Hank de Carbonel; David Hopkins; Glenn Frazier; Sue Rodgers; Shelby Kandel; Horat Huettenhain; Greg Fisher; George Clatterbuck; Rusty Najjar; Judy Silvas; J. Walker; Valerie K. Collins; Carolyn Bogush; Linda Gooden; Barbara Riis-Christensen; Gary Hess; Sharon Skinner; DWE; Ross OBrien; Raymond DiLorenzo; Duane Maddox; Mel Winn; Ken Joyce; Gary Risley; John Webb; Gary Martinez; Michelle Benitez; Pat Onato; James Gallno; Jack Lowe; Natalie Gravitt; Joseph Berger; Allan Merrill; Ed Clark; Elaine Bashford; Dianne M. Foster; Mary A. Bordi; Linda Gilbert; Amin Salkhi; Jerry Mercer; Shawn Ronk; Matt Kovanda; Greg Ronk; Sandra Waters; Alan Andersen; Heather Ronk; Robert W. Blakeslee; Sharon Lewis; Sally Rapoza; Doyle Lewis; Bob Moulden; Michael Murray; Mary Costa; Aaron E. Nowling; Rocky A. Rodgers; Suzanne Candler; Ron Holland; James Ernst; Clinton Ingram; Cheryl Ingram; George Weaver; Steve Mars; Ronald Bales; Maria Aranda; Jeff & Sue Thomsen; Alfred Wulff; Thomas Galloway; Dan Francis; J. Marshall; Jesse Halsell; Jerry Koch; Lynn Lokey; Jack Owen; Jack Loris; Jerry Mitchell; Pamela Mitchell; Jeff Bankston; Cheryl Quiring; Lisa Vargas; Veldon Leverich; Colleen O'Brien; Joshua Jacobs; Lee Stinson; Carl Wilson; Robert Edwards; Matthew Vice; Theodore Gilbert; Thomas Ebbers; Andrew Rowe; Bob Owen; Walter Rice; Rosella

	Adams; Rick Dobbs; Richard Laing; George Fleming; Ken Davis; Howard Thomas; Dennis Lowry; Dina Medici; Jack Wertz; Nathon Dyck; Richard Bishop; Joe Reed; Kimberly Donaldson; Jim Griffith; Sid Jelinek; Karen Mattox; Melinda Rice; Judith A. Allen; Marillyn Ratliff; Ed Oddy; Don Dickerman; Ramin Akhbari; Gwen Myers; April Dobbs; Jan Hansen; Charles O. Greenlaw, P.E.; Michael Powell; Frank Palmer; Bruce Lownsbery; Guillermo Rodriguez; Larry Virga; Lori Patterson; Charles Glahn; Smith Virgil; Pat Dilling; Camille Hald; Steven Rainwater; Nels K. Ahnlund; Cari Vinci; Ellis Andrada; Gary W. Smith; Thomas Davison; Scott Connors; Paul Settle; Jesse Glenn; Gerald A. LeFor; Christopher L. Anderson; Ken Hokanson; Gary Hayworth; John Schoeppach; Anita Schoeppach; McKenzie Johnson; Kent Johnson; Steven Willman; Michael Curry; Steve Donica; Carl Guastaferro; Bonnie McAdams; Ann Myers; Greg Myers; Richard Mortimer; Stephen Holben; James Valliant; Betsy Speicher; Reno Gazzola; Travis Tolle; Victoria Coots; Gary Loope; Claudia Aposhian; Ken O'Neal; Brenda Swan; Dean Patterson; Jennifer McCarthy; James M Jenkins; Lancy McCray; Steve Welstand; Nancy Long; Minette Floyd; Josephine Black; James Darrel Stewart; Jorge F. Vargas; Paul & Trudy Schmitt; Holly Ritter; Joseph W. Waterman; Karen Smart; Ruby Gutierrez; Randy Rowland; Terisa Rowland; Diane; Fay Almond; Greg Saunders; James Mulvihill; Sarah M.; Joseph Murguia; Sharon; Doug Lower; Keith Kessler; Brian Jones; Dustin Jones; Russell Nelson; Stan McMaster; Rev. Matthew Weyuker; Keith Morrison; Barbara Sloan; Steven Hill; Jimmie Brooks; David Dahlberg; Amy Freeland; Randy Freeland; Jon R. Herbold; E. Copeland; Gary Martin; Russ Steele; Trina Burton; John Krivacic; Marianne Holtzinger; Thomas W. Brown, DO; Carol Demann; Ken Roberts; Arthur Dorall; San Castorani; Charles Jensen; Lenny Redwine; R. Roberson; Barbara W. Vargas; Ronald Vargas; William Halliday; Aaron Lonquist; Bonnie Webber; John T. Larimer, Jr.; Sandra Stufflebean; Robert Trevett; Todd Wilson; Don Paolino; Alan Kellogg; Jerry Collins; George Rebane; Kim Sanchez; Pamela S Johnston; Robert Mason; Barbara; Paul Fischer; Jo An Rebane; Orion Weihe; Bob Edmonds; Alex Aliferis; Kenneth Foy; Elaine Fracchia; Jim Griffith; William Houlihan; Scott Albright; Tracy DuBord; Tony; Jan Rudnicki; Ted; G. Rogers; Lawrence Scheid; Shane Thomsom; Carmel; Lloyd Schultz; Greg Wallace; Laurie Wallace; Sarah Bond; Ken

	Davis; Charles B Keele; Michael Lande; Phyllis Wing; Jim Reid; William Little; Shawn Johnson; Rudy Marin; Karl Ulriksen; Troy Bogert; Jim Tallarico; James Malmberg; Nathan Johnson; Tito J. Mena; Gary Hill; Saudra Fuller; Richard Staehnke; Robert White; Robert Walker; Pat; Ross Bogert; Richard Sherman; David Jamerson; Lyndsay Friar; Chris Taylor; Chris Taylor; Cary Friar; Drew Friar; Linda Taylor; Ken Taylor; Walter Babigian; Marie Roberson; John Kemp; Stuart Dodge; Seannon Garriepy; Robert Dietrich; Jerry Landgraff; Wayne Johnson; James W. Ricketts; Kathy Gean; Kevin L Wildman; Mary Parigoris; Mark Shear; Bill Roser; William Loi; Shirley Freeman; Frank Chambers; Kevin Davis; Lew Herndon; Patrick Newman; Richard Leake; Larry Louviere; Drew Tomlinson; Allen Gwilt; Steve Payne; Evelyn Nokelby; Aaron Bento; Jacqueline Stewart; Joe Murphy; Kelly Eaton; Ronald Tachibana; Todd Friar; Shane Becker; Edith Driver; Ken Koppenjan; Yvonne Cornelius; Ryan Nakken; Kathy West; Ken Dyche; Stan Johnson; Mike Strode; Stephen Swartz; Mariluz Buchanan; Eric Leonetti; Richard Moore; E Miller; Anita Zerrer; Dalt Williams; Tom Tanton; Mardi Douglas; Laura Kramer; Kathleen S; K. OQuest; Debra Gaylord; William Jurls; Eric Stroud; Mark Jeghers; Devon Graham; Richard Stevenson; John Mills; Eric Eisenhammer; Martin K. Bertelsen; Cathy Diaz; Beth Calvert; Brent Brown; Tracy Brown Written Testimony: December 16, 2011

* Commenters who submitted but did not sign the comments
WT = Written testimony submitted at the Board Hearing
OT = Oral testimony given at the Board Hearing

B. Crude Oil Provisions

This section contains comments specifically related to the crude oil provisions of the LCFS. This includes comments pertaining to the treatment of crude carbon intensity (CI), updated baseline values, revised CI values, calculation methodologies, revised compliance schedules and lookup tables, reporting requirements, crude shuffling, and overall provisions.

B-1. **Comment**: We support the efforts made to modify the HCICO provision by ensuring a more level-playing field that raises the bar equally for both fuel importers and domestic producers. Specifically, we understand that importers of all unfinished and finished products will be held to the same bar under the Low Carbon Fuel Standard's High Carbon Intensity Crude Oil Provision (HCICO) and will need to offset their emissions and introduce cleaner, alternatives just as

California fuel producers are starting to do today. Doing so will prevent “leakage" of California's jobs and its market to imported fuels from states and countries that do not participate in similar programs. (BGA1)

B-2. Comment: We support the efforts made to modify the HCICO provision by providing refineries greater flexibility to buy and sell crude oils without penalty so long as the average performance does not worsen over time. The proposed modifications "grandfather" the carbon-intensity of refineries rather than 2006 baseline crude oil sources. Doing so provides greater flexibility for refineries to buy and sell crude as normal, with debits accrued only if actual performance worsens going forward. Greater environmental benefits will also be achieved since this new approach is more performance-based. (BGA1, NRDC1)

B-3. Comment: We support the efforts made to modify the HCICO provision by providing incentives for generating credits for upstream reduction activities that reduce crude production emissions could help spur innovative projects. (NRDC1, BGA1, ALA2)

Response: Acknowledged.

B-4. Comment: We urge you to reject the big oil companies' requests for accounting changes that would exempt dirty, high-carbon fuels such as those created with Canadian tar sands and other HCICOs and weaken the LCFS by exempting dirty high-carbon fuels. If the oil industry had their way, all petroleum fuels would be treated the same under the LCFS, leading to an influx of ever-dirtier sources of petroleum into California. As now crafted, the low carbon fuel standard encourages oil companies to invest in cleaner fuel solutions and do not let that change. Reaffirm your strong support for the standard, and send a signal that California remains serious about reducing greenhouse gas emissions and reducing our dependence on dirty, carbon-based fuels. (FORMLETTER5, COFFEY)

B-5. Comment: The Board should not only adopt the modifications to the HCICO provisions, but also improve it in one critical way. From 2006 to 2010, staff has shown that the carbon intensity of our fuel pool actually increased by one percent due to HCICO. We strongly support accounting for emissions from High Carbon Intensity Crude Oils and urge ARB to adopt an option for refinery-specific accounting to improve equity and to align responsibility with performance. We recommend that the Board adopt the Proposed Amendments as drafted, and adopt a resolution instructing staff to make a key 15-day change to improve the regulations. We urge ARB to adopt an option for refinery-specific accounting to improve equity and to align responsibility with performance. If the amendments are adopted as drafted, all refineries selling product to California will be free to buy and sell crude oils as before and will only be debited if the carbon-intensity of all California refineries and importers worsens over time. This contrasts with the earlier approach that would have applied penalties *specifically* to refineries for crude oils which were above a "bright line" of 15 grams CO_2 per mega joule and which were not part of the original 2006 crude oil slate. Under the Proposed Amendments, however, an increase in carbon intensity at one refinery is not assigned to the responsible refinery, but is instead spread across the entire sector statewide, and refineries selling higher-carbon products to California will be debited only if the statewide carbon-intensity of all California refineries and importers increases over time. Such a system dilutes the signal to the responsible parties and provides the opposite signal to refineries that may be keeping the carbon-intensity of their crude oil slate constant (or actually improving it). We therefore propose that at a minimum, ARB should provide refineries with the option to report their own refinery-specific emissions deficits due to the use of HCICOs should be assigned to the responsible refinery, in keeping with a "polluter pays principle." The Proposed Amendments should be strengthened to ensure that all deficits due to the use of HCICOs are assigned to the responsible refinery. (NRDC1, CBD, NRDC4, NRDC5, CEERT)

B-6. **Comment:** The LCFS must account for dirtier, higher carbon fuels and ARB must stay the course in implementing this critical clean air program on schedule. We urge the Board to vote to ensure that oil companies phase in cleaner fuels and phase out dirtier fuels. The Board must direct ARB staff to strengthen their proposal by ensuring that each oil refinery properly accounts for its use of dirtier oil sources such as tar sands. Requiring individual refinery accounting will ensure that each refinery is directly responsible to offset its own, additional carbon pollution. (FORMLETTER1, FORMLETTER2, ALA1, ALA2, CBD)

Response: We acknowledge the support for a strong crude oil provision founded on a policy of accurately accounting for emissions associated with crude oil production and transport. The commenters also recommend shifting to a company-specific approach or allowing for some refiners to opt for company-specific accounting. Upon consideration of various alternatives, including both hybrid and company-specific approaches, the Board determined that the California Average approach in the proposal was preferable for the reasons discussed in the Staff Report (pp. 30-42). The evaluation of alternatives is discussed on pages 77 through 84 of the ISOR. Although the Board approved the California Average approach at the December 2011 hearing, the Board in Resolution 11-39 directed the Executive Officer to evaluate and propose, as appropriate, an option for individual regulated parties to have their deficits for gasoline and diesel determined on a refinery-specific basis that accounts for the carbon intensity of domestic and imported crude oils, intermediate products, and finished fuels. Accordingly, staff will continue to evaluate such refinery-specific approaches and propose, if appropriate, a regulatory provision for possible Board consideration in a future rulemaking.

B-7. **Comment:** The Proposed Amendments should require refineries to report actual crude oil use by marketing name, production method and parameters as needed, and ultimately the corresponding carbon intensity values. It is our understanding there may be insufficient reporting of such data by all oil companies, causing staff to resort to alternative sources to develop the carbon intensity values on their own, as was necessary for the Proposed Amendments. Effective implementation of the HCICO provision and the recommendation made above to hold either the industry or individual refineries accountable for HCICO use will not be possible without a mandatory reporting requirement. Going forward, relying on voluntary cooperation, which has been slow and inconsistent to this point, will further delay the implementation of the changes. (NRDC1, CBD, NRDC4)

B-8. **Comment:** On the constantly interesting issue of high carbon intensity crude oil, I'd like to echo the sentiment from the Consul General from Canada. I think there is an important direction of travel here, not just for California, but for the rest of the world, where transparency and full life cycle assessment of crude oil is something that needs to be moved towards in one way or another. I hope that California can be part of an increased reporting regime that will help us close the information gap between jurisdictions. (ICCT)

Response: Although the carbon intensity estimates would be improved by more extensive reporting, commenters to the first 15-day Notice requiring detailed information on MCON location and production data, raised issues and complexities associated with requiring regulated entities to provide such detailed information. In response, with regard to field-specific production parameters, ARB will continue to collect crude oil recovery data from numerous available, independent sources. Oil producers are also encouraged to supply data to ARB in order to help maintain a robust database.

B-9. **Comment:** The average carbon-intensity of the crude slate should be updated annually to provide a timely signal to companies to avoid increases in gasoline and diesel emissions. The Proposed Amendments are ambiguous as to this requirement, which should be made explicit. (NRDC1)

Response: As described in part II of this FSOR, the regulatory language was modified from the original proposal to specify that each year ARB staff will calculate a California Annual Crude Average carbon intensity value. This Annual value will be compared to the Baseline value to determine if incremental deficits will be applied.

B-10. **Comment:** Claims that oil companies are making substantial investments in renewables are not accurate. They are making very little investment in renewable fuels as compared to their investment in extracting oil from tar sands. (NRDC4, PADULA)

Response: The regulation specifies performance standards, but investments by oil companies are not required under the LCFS regulation. The LCFS regulation provides incentives to oil companies and other fuel providers to invest in technologies to generate low carbon intensity transportation fuels to meet the compliance targets of the regulation. The regulation only requires fuel providers to meet the targets.

B-11. Comment: I am writing to ask that the Board reject the oil industries requests to annually review the LCFS standards in light of progress in their reductions of greenhouse gas emissions from burning fossil fuels. (POTASH)

Response: The Board has directed staff to perform periodic reviews of the regulation to ensure compliance. There is no provision in the regulation to modify the standards annually as is being suggested by the commenter. However, section 95489 already requires two formal program reviews, the first of which was conducted in 2011, and the next one to be presented to the Board before January 1, 2015.

B-12. Comment: I think it's important to bear in mind that there are more responses to a full crude differentiation than simply shuffling. There are efficiency opportunities at refineries. If a value signal can be provided, there are opportunities to achieve very significant carbon savings, from flaring, opportunities to move investments towards lower carbon crudes in the future and away from higher carbon fuels. I would like to mention that I think crude efficiency and carbon savings from crude can be a compliance pathway as well as a burden as crude differentiation moves in. (ICCT)

Response: We agree that differentiation of crudes may lead to improvements in efficiency of production as well as move investments toward lower carbon crudes. The calculation of the Annual Crude Average carbon intensity will account for improvements in crude recovery that result in carbon emission savings, including flaring reductions at crude production facilities. Furthermore, the regulation was modified to include provisions for earning credits when innovative methods to reduce GHG emissions are employed. Finally, refinery efficiencies are being addressed by a separate regulation: "Regulation for Energy Efficiency and Co-benefits Assessment of Large Industrial Facilities."

B-13. Comment: Shuffling happens for a lot of reasons as part of normal business practices in the industry. There could be examples of shuffling that actually reduce greenhouse gas emissions, not just the examples that industry has been asking us to focus on in terms of increasing emissions. (CEERT)

Response: We agree with the commenter that shuffling can both increase and decrease greenhouse gas emissions, depending on the resulting shipping distances. Moreover, the amendments require an Annual Crude Average carbon intensity value to be compared each year to the Baseline Crude Average value. As a result, the industry as a whole, rather than individual crude sources, has a disincentive to allow the Annual Average crude carbon intensity from increasing relative to the Baseline Average. Such an approach will allow flexibility for fuel producers to use different carbon intensity crudes as long as the average carbon intensity remains the same and, thus, reduce incentives for shuffling. Based on this, we believe the average approach is likely to reduce shuffling.

B-14. Comment: The Environmental Impact Analysis for the Proposed Amendments fails to evaluate the potential air quality impacts of the processing of "additional volumes of imported, higher CI crudes" at existing refineries as well as new facilities in California. The analysis also determined that any adverse impacts due to criteria and toxic air pollutants from changes in the crude slate would be subject to mitigation due to existing stringent NSR [New Source Review] regulations. However, NSR might not capture or prevent increased emissions resulting from changes in the crude slate processed at existing refineries. New Source Review applies only to new and modified facilities. The Environmental Impact Analysis does not discuss this scenario or the potential that adjusting the baseline upward and "grandfathering" HCICOs into the baseline could result in the increased processing of heavier, higher-carbon crudes. (CBD)

Response: Staff evaluated all potential air quality impacts of the proposed amendments within the Environmental Impacts Analysis section of the ISOR. Staff expects the proposed HCICO provisions to result in no additional adverse impacts to California's air quality due to criteria and toxic air pollutants relative to the current regulation as described in pages 56-61 of the ISOR. Stationary sources in California, including refineries, are regulated primarily by the local air districts based on local air quality and other considerations specific to those districts. As such, refineries have to comply with their local air district's permitted levels of criteria and toxic pollutant emissions and CEQA requirements. Changes to permitted operations would have to be submitted to the local air district for approval, which would include an environmental review, opportunity for public comment and incorporation of all feasible mitigation for any impacts identified.

B-15. Comment: WSPA does not support staff's proposed revision to crude oil treatment called the CA Average approach, nor do we support any refinery specific approach. WSPA does not support any form of crude differentiation treatment within the LCFS. We support a simple crude equivalency approach that does not discriminate between crude oils. The reasons for this are:

- It simplifies an already complex regulation and provides certainty to the standards to be achieved,
- It provides overall certainty and stability to the marketplace, and reduces the cost impact of the regulation,
- It eliminates crude differentiation and any potential negative marketplace impacts such as the initiation of CA crude oil exports due to the policy,
- It focuses the intent of the LCFS program on the development of low carbon and innovative alternative fuels,
- It provides for equal treatment of all refineries—including out-of-state and international refineries,
- It avoids the difficulties and complexities regarding CI accounting of imports of products, intermediates or blendstocks,
- It eliminates the need for development and use of complex crude CI accounting systems,

- It helps alleviate discrepancies between countries where detailed information is known about crude production processes, and countries where very little accurate data is available,
- It totally eliminates crude shuffling attributed to the program,
- It eliminates potential negative impacts on California and US energy security,
- It allows jurisdictions in crude producing areas to manage GHGs (such as existing Canadian federal and provincial GHG regulations) without concern over competitive disadvantages,
- If the LCFS spreads to other jurisdictions/regions (22 states currently contemplating), it sets a simple and positive precedent for treatment of crudes in those areas, rather than having jurisdictions try to determine how to deal with a CA average approach versus another crude oil approach elsewhere that creates variations in gasoline and diesel CI values.

We do not support the staff's proposed California Average approach or any of the other optional approaches that were investigated by staff. In particular, we oppose the individual refiner crude oil approaches. (WSPA1, WSPA2, WSPA3, BP1, BP2, VALERO, TESORO, CLARK)

Response: As discussed on pages 77 to 84 of the ISOR, we evaluated six alternative approaches for the treatment of crude oil in the LCFS regulation, including the crude equivalency approach recommended by the commenters. Each of the six alternatives has several advantages and disadvantages. We agree that many of the numbered items listed in the comment could be considered advantages of the crude equivalency approach. Similar lengthy lists of advantages could be developed for each of the other approaches.

However, our assessment was primarily based on how well each of the alternatives met four key guiding principles. These principles were chosen to ensure that the core objectives that led to the creation of the LCFS and the existing crude oil provision would be preserved. The key guiding principles are:

- Providing accurate accounting for emissions from production and transport of crude oil;
- Discouraging potential increases in emissions and ensure that increases that do occur are mitigated;
- Promoting innovation for emission reduction activities; and
- Avoiding or limiting incentives to use crude shuffling to generate credits, avoid deficits, or transfer GHG emissions to other jurisdictions to avoid regulation under the LCFS.

Although the crude equivalency approach advocated by the commenters eliminates any incentive for crude shuffling in response to the LCFS, it fails to provide accurate accounting of emissions, discourage potential increases in emissions, and promote innovation for emission reduction activities. As discussed on page 84 of the ISOR, the crude equivalency approach does not account for, track, or mitigate increases in upstream emissions from crudes used by California refineries. This is inconsistent with the life cycle analysis basis of the LCFS, as approved by the Board in 2009, and undermines the program's goal to achieve a ten percent emission reduction from the 2010 baseline for transportation. The crude equivalency approach provides no incentive for oil companies that produce their own crude oil to reduce emissions (e.g., by reducing flaring) since these reductions will have no benefit relative to their compliance with the LCFS. Because the approach provides complete flexibility to purchase worldwide crude supplies irrespective of the emissions associated with producing and transporting the crude, no mitigation would be required if higher crude CIs were to be used. Moreover, this approach could result in significantly greater amounts of harder to refine crude oil being used at California refineries because there is no incentive to avoid their use. Consequently, the crude equivalency approach could have adverse environmental impacts for the communities located in the vicinity of the refineries. On the basis of this evaluation, we determined the crude equivalency approach to be inadequate and inconsistent with the key guiding principles for crude oil treatment under the LCFS.

B-16. Comment: The ISOR does not include a key discussion on the competitive impacts of all of the optional crude treatment approaches. One of the key changes in the California industry average approach is the sharing of the penalties to the California refining industry due to California industry crude oil selections. The ISOR does not include any competitive analysis of the California refining industry (refining capacity, market share, etc.). It also does not discuss that this is a precedent-setting penalty mechanism. WSPA requests that this analysis be performed and included in the documentation for this hearing. (WSPA2)

Response: We initiated the data collection phase of a competitiveness analysis by sending out a survey to the petroleum companies participating in the LCFS on August 8, 2011. As part of the survey, we requested data on a number of production parameters, including:

- Crude slates for 2008, 2009, and 2010;
- Imported intermediates and finished products; and
- HCICO versus non-HCICOs in crude slates.

We received responses from only a small minority of survey recipients. These responses did not provide us with a sufficient basis on which to perform a competitiveness analysis.

B-17. Comment: ISOR discusses complex topics like crude treatment with unclear language resulting in poor communication. As an example, in the economic analysis section, it refers to "in-basket" HCICOs. HCICOS only exist in Option I. (WSPA2)

Response: We agree that it would have been preferable to use the term “high carbon intensity crudes” instead of HCICOs when describing “in-basket” crudes with much higher than average production and transport emissions.

B-18. Comment: There also seems to be a process issue in that the Regulatory Amendments has a new baseline based on 2009. In the 15 day change to amendment period, staff plans to update the baseline to 2010. The simplified basis for the 2009 baseline is a set of assumptions/default CIs at the country level. It is inferred that the update to the 2010 baseline will be based on ARB's new crude model at the MCON level. Likewise, the only option for a crude CI is now the ARB model (referred to as savings from running Method 2B). At a minimum, the 2010 baseline must be on the same basis as the annual update. It is irresponsible to claim improved accuracy before the new model is peer/industry reviewed. The same verifiable data issues still exist for developing any crude CI which consultants like IHS CERA and Jacobs have discussed. (WSPA2)

Response: The commenter is correct that the update of the Baseline Crude Average carbon intensity to the year 2010 will be accomplished using a new lifecycle assessment model for estimating emissions from crude oil recovery and transport (Oil Production Greenhouse Gas Emissions Estimator, or OPGEE) developed at Stanford University under contract with ARB. OPGEE v1.0 was incorporated into the regulation by reference, and the update to a 2010 Baseline was done as part of the 3rd 15-day Notice. We conducted two workshops allowing for stakeholder review of the model. Prior to the first workshop on March 19, 2012 we released the Beta version of the model and prior to the second workshop on July 12, 2012 we released Draft version A of the model, 160 pages of model documentation, and detailed model inputs and carbon intensity values for crudes supplied to California refineries during 2010.

B-19. Comment: Section 95486 (b)(2)(A)(1) "descriptions of CIs," uses "crude used" as the basis for the annual calculation. This is inconsistent with the additional data requirements of crude supplied/imported. (WSPA2)

Response: We agree with the comment. The Baseline and Annual Crude Average carbon intensity values will be calculated using data for crude oil supplied to California refineries during the baseline year or given compliance period. A correction to the regulation order has been made as part of the first 15-day notice.

B-20. Comment: Section 95486 (b)(2)(A)(2) descriptions of the basis for distributing the incremental deficit is unclear. It refers to "CARBOB and CARB Diesel supplied" which could be interpreted differently from Section 95486 (b)(2)(A)(l) description of "CARBOB and CARB Diesel produced or imported." The use of more precise terms of "production" or "compliance obligation" to identify the basis would provide better clarity. (WSPA2)

Response: We disagree and believe that using the terms “production” or “compliance obligation” in this section would be more confusing.

B-21. Comment: The ARB proposed likely notification of revised annual crude averages in the 3rd quarter every year and applying the values to fuel produced 3 months later, is too short for planning. We urge ARB to provide at least 6 months advance notice of any revisions to the California crude average. (WSPA2)

Response: We agree with providing as much advance notice as possible for the Annual Crude Average carbon intensity value. We are, however, restricted by the allowance for annual reporting to be completed as late as April 30 of the year following the end of the compliance period. Reporting of marketable crude oil names and volumes necessary for the calculation of the Annual Crude Average carbon intensity value will be made as part of the annual report.

As part of the first 15-day Changes, we have proposed using a three-year rolling average for the Annual Crude Average carbon intensity value. A three-year rolling average improves forecasting and significantly lessens the potential for refiners to be surprised by a large incremental deficit.

B-22. Comment: WSPA requests ARB consider a three-year rolling average for evaluating the California average as this would avoid potential extraordinary variability in crude slates with impact to the California average. In order to maintain the current 2014 application year for ARB's approach, this averaging would be phased in over time. (WSPA2, CONOCO1)

Response: We agree with this comment and have revised the regulation order as part of the first 15-day notice to calculate the Annual Crude Average carbon intensity value using a three-year rolling average, which is phased in over a three year period.

B-23. Comment: Since the 2012 California average calculation that would be used in incremental deficit calculations in 2014 will involve an Adam Brandt tool that is not yet final or peer-reviewed, and the final tool may involve calculation methodology changes—changes to the average because of the calculation method changes (vs. updated crude CIs or crude slate changes) should be accompanied by adjustments in the compliance targets. (WSPA2)

Response: We agree with this comment. If any changes are made to the methodology for calculating the yearly Annual Crude Average carbon intensity value, we will evaluate the effect of these changes on the Baseline Crude Average carbon intensity value and update the compliance schedule targets, if necessary.

B-24. Comment: Innovative technology incentive proposal—ARB should not calculate the annual average California crude CI on a "pre-innovative method" basis. If ARB is going to continue with a "California Average" approach, ARB should calculate this annual average California crude CI based on the best estimates of the CI's of the individual crudes used in California, not a "pre-innovative method" CI. ARB's concerns about incentives for innovative methods, such as CCS, creating potential double counting of credits should not come at the expense of penalties to refiners that are not using the crude produced using innovative methods. (WSPA2, SHELL)

Response: We agree with this comment and have removed the requirement for calculating the Annual Crude Average carbon intensity value on a "pre-innovative method" basis as part of the first 15-day change notice.

B-25. Comment: It has been BP's long held position that the LCFS should not differentiate and penalize crude oils—and instead should focus on the primary objective of driving innovation in and deployment of new, alternative low carbon fuels. This position is supported by analysis that shows no environmental benefit from crude differentiation—only potentially severe impact to refiners and consumers. Differentiation of crude oils in a LCFS is inadvisable for several reasons.

- First, we believe there is not a reasonable, accurate or fair method to determine the crude oil origin and carbon intensity of any and all crude oil, refined product or intermediate product used in California.
- Second, the purpose of this challenging LCFS regulation, as stated by CARB, is to drive "innovation in new, low carbon fuels such as biofuels, electricity, hydrogen and natural gas." The LCFS was never meant, nor is it well suited, to deal with emissions from large stationary sources—such as those associated with the production of crude oil. There are other policies which are much more effective and suitable for addressing those categories of emissions.
- Third, and perhaps most significantly, CARB staff have never demonstrated an environmental benefit from differentiating and penalizing crude oils in the LCFS. Instead, they seem to rely on a desire to simply send a signal to worldwide producers of crude. In fact, staff have ignored compelling analysis which demonstrates that a program in California that penalizes certain crude oils will more likely serve to shuffle the distribution of crudes (resulting in an overall increase in GHG emissions) rather than impact upstream production methods in other countries.
- And finally, while there are no demonstrable benefits from differentiating crude oils in the California LCFS, there is clearly impact to California refiners—and ultimately to fuels consumers from this policy. These impacts are demonstrated in an analysis performed by Wood McKenzie for WSPA which shows significant impact to California refiners from a policy which reduces or penalizes their choice of crude oils. Moreover, the WM report is not the only analysis to conclude that these crude oil provisions of the LCFS would be harmful to California refiners and consumers. The California Energy Commission (CEC) analysis contained in their recent draft 2011

Transportation IEPR Report underpins the conclusions of the WM study. According to the CEC, these crude oil provisions of the LCFS have "the potential to affect the crude oil selection decisions of California refiners," that "Replacing a portion of the existing crude supplies and instead using other sources of crude oil could lead to increased crude acquisition costs," and that these LCFS crude oil provisions "could impact refiner profitability and the ultimate cost of petroleum fuel in California."

In summary, to support their desire to differentiate and penalize crude oils, staff is assuming environmental benefit where there is none—and ignoring clear evidence of impact to refiners and consumers. As evidenced by the CEC conclusions, staff is asking California consumers pay higher costs for transportation fuels so that CARB can send an ambiguous signal to foreign crude producers to lower their GHG emissions in foreign countries. (BP1, BP2)

B-26. Comment: California Independent Petroleum Association (CIPA) is concerned that certain amendments to the LCFS could have the unintended effect of disrupting supply or adding artificial volatility to transportation fuel costs that would be counter to the goals of the LCFS. (CIPA1)

B-27. Comment: I haven't seen a thorough analysis on this from CARB or the Energy Commission. And I think we need one. I'm happy to do it collectively, but I think it's that important that it needs to be done. (WSPA3)

Response: The LCFS is a performance-based regulation built upon the application of lifecycle assessment to determine the well-to-wheels carbon intensity for each fuel. Although the Board acknowledges that both the data requirements and modeling used to estimate carbon intensity values involve some amount of uncertainty, they have ruled in adopting the LCFS that the state of life cycle assessment is mature enough to form the foundation of the regulation. Furthermore, these amendments to the LCFS require the reporting of information necessary to determine the origin of all crude supplied to California refineries.

The LCFS is designed to account for all emissions over the lifecycle of a fuel, and a benefit of the lifecycle analysis methodology is flexibility to apply to all stages of the lifecycle, including stationary source emissions. Although driving innovation in new, low carbon fuels such as biofuels, electricity, hydrogen and natural gas is a priority under the LCFS, and the goal of the regulation is to reduce the average carbon intensity of transportation fuels sold in California by ten percent in the year 2020. Ensuring this goal is met is not possible without accurately accounting for emissions associated with the production and transport of crude oil and requiring that increases that do occur are mitigated. For further discussion see the response to comment B-15.

Commenter states that distinguishing between crudes on the basis of CI under the LCFS will likely lead to shuffling of crude rather than impact upstream production methods and therefore will increase costs to California refiners and consumers while providing no environmental benefit. These objections apply generally to all alternative crude provisions that differentiate crude based on emissions associated with recovery and transport, including the provisions appearing in section 95486(b)(2)(A)2 of the original LCFS regulation. Those original provisions have already been subject to an impact assessment, as part of the original public rulemaking process. Although the Initial Statement of Reasons covering this rulemaking analyzed a crude equivalency alternative, the inclusion of that alternative does not override the provisions of the original regulation calling for crude differentiation based on CI. A comment calling for crude equivalency would have been within the scope of the initial rulemaking, but it is not within the scope of the current rulemaking. Moreover, the rationale behind the rejection of the crude equivalency alternative and the adoption of the California Average alternative is provided in the response to comment B-15.

The Initial Statement of Reasons covering the current rulemaking concludes that assessing the incremental compliance cost impacts of the proposed amendments requires evaluations of the case in which the California Average CI is maintained, as well as the case in which the average CI rises. Although costs under each of these scenarios can be characterized, combining the two outcomes into a single estimate of the compliance cost of the amendments is difficult. In sum, however, compliance costs will be minimized by two factors:

- Adopting a 2010 baseline, which will produce a higher average CI than the previous 2006 baseline; and
- Under the original provisions, any purchase of an “out-of-basket” HCICO would generate a CI deficit that would have to be offset through the use of lower CI fuels or the retirement of credits. Under the proposed amendments, however, the “basket” concept is done away with, and all crudes receive specific CIs. Some of will be lower than the CA average, making it possible to partially or wholly offset high-CI purchases with lower-CI crude purchases. Such offsets were not possible under the original provisions.

The increased flexibility made possible by these two aspects of the proposed California average approach indicate that the compliance costs of the amendments should be no higher than (and possibly even lower than) the compliance costs of the original provisions.

B-28. Comment: The WSPA2 comment included two attachments: a critique of ARB’s illustrative scenarios and economic analysis by Jim Lyons of Sierra Research, and a presentation of the results of a crude transport impact assessment by Wood-McKenzie. (WSPA2)

B-29. Comment: California Independent Petroleum Association (CIPA) is concerned that certain amendments to the LCFS could have the unintended effect of disrupting supply or adding artificial volatility to transportation fuel costs that would be counter to the goals of the LCFS. Moreover, it is our view that the proposed changes to the program could have the perverse effect of increasing greenhouse gas emissions, even inadvertently and/or extra-regionally, which would be counterproductive. These comments are submitted to express CIPA concerns over the current effort to adopt amendments to the LCFS, particularly in regards to the changes that move from a production default carbon score to a statewide average score with differentiation based upon marketed crude names and/or field names and compared against a statewide average. (CIPA1)

Response: Neither of these submittals is within the scope of the 45-day Notice for this rulemaking. The Lyons report was submitted to the Board in response to the Advisory Panel Program Review. The Advisory Panel Program Review was a non-regulatory review of the LCFS program presented to the Board by an advisory panel convened by ARB staff, as required pursuant to section 95489 of the LCFS regulation. It was not intended to respond to the proposed LCFS amendments. It focuses on the illustrative scenarios and related economic analysis included in the Program Review report. Neither the scenarios nor the economic analysis were included in the documentation supporting the proposed LCFS amendments. Like the previous comment B-28, the Wood-McKenzie report is concerned not with the incremental effects of a transition from the original HCICO provisions to the discriminate among crudes on the basis of carbon intensity. Such an attempt, according to the report, will result in longer crude oil transport routes at lower-CI crudes are attracted to California and higher CI crudes are deflected to other markets. The Wood-McKenzie presentation does not distinguish between the existing and the proposed HCICO provisions in terms of the potential to realign crude tanker routes. As such, it does not address the specific question being addressed in the FSOR: what are the incremental differences between the current HCICO provisions and the proposed amendments?

B-30. Comment: ConocoPhillips continues to support the "no crude differentiation" approach based on enforceability and "level playing field" aspects communicated in earlier testimony and comments. CARB staff convened a multi-stakeholder LCFS Advisory Panel (of which we were a member) to review this very issue over a 9 month period. The pros and cons of various approaches were discussed and examined. We view the California average approach as proposed by Staff an improvement to the existing regulation. In addition, CARB staff's proposed amendments more accurately account for crude carbon intensity and it is a simpler approach. (CONOCO1, CONOCO2)

Response: Please see response to comment B-15 concerning “no crude differentiation.” We agree that the CA Average approach is an improvement over the original crude oil provision.

B-31. Comment: As currently drafted, the proposed amendments only contain an "incremental deficit" if the California average goes up. If the California average goes down, there should also be an ability to generate an "incremental credit." Such an approach further encourages directional improvements on crude approaches with no compromise of the California LCFS target. (CONOCO1)

Response: As stated on page 81 of the ISOR, one of the key guiding principles used by staff in evaluating alternative crude oil provisions is “avoiding or limiting incentives to use crude shuffling to generate credits, avoid deficits, or transfer GHG emissions to other jurisdictions to avoid regulation under the LCFS.” Allowing for an “incremental credit” to be earned if the Annual Crude Average carbon intensity is reduced below the Baseline Crude Average value will directly incent the shuffling of crude sources in order to earn LCFS credit. The CA Average crude oil approach balances competing goals to discourage an increase in emissions from crude oil production and transport while also minimizing the incentive to shuffle crudes. The approach gives refineries the discretion to shift among available crude sources without incurring an incremental deficit as long as the Annual Crude Average carbon intensity value does not increase relative to the Baseline Crude Average value. In essence, the CA Average approach is designed to maintain the status quo and limit the potential for shuffling of crude in order to avoid deficits associated with purchasing individual crudes (as may have occurred under the original HCICO provision) or to generate credits as suggested by the commenter.

B-32. Comment: ARB should establish a de minimus level (e.g., 5%) where incremental deficits (and credits) would only apply if a change in the California average crude carbon intensity exceeds this threshold. (CONOCO1)

Response: We disagree with the use of a de minimus level above the Baseline Crude Average carbon intensity that must be exceeded prior to incurring incremental deficits, because this could lead to a significant emissions increase over the course of the regulation which is not mitigated. The de minimus level of 5 percent recommended in the comment would be the approximate equivalent of a 0.5 gCO_2e/MJ increase in carbon intensity above the baseline. In the year 2014, the LCFS requires an approximately 1.5 gCO_2e/MJ reduction in the overall carbon intensity of transportation fuels. Therefore, establishing a de minimus level could potentially reduce the overall effectiveness of the LCFS by 33 percent in the year 2014, the equivalent of about 0.8 MMT CO2.

B-33. Comment: §95484(b)(4)(B); Requires refiners to report whether the crude oil was produced using Thermally Enhanced Oil Recovery (TEOR) or non-TEOR methods. Suppliers, however, may withhold the requested data as "confidential business information" in a crude oil transaction. The bottom line is that CARB is requesting refiners to report information that they do not know and to which they lack access. (CONOCO1)

Response: In the third 15-day Change Notice we have proposed limiting the reporting requirements for crude oil. The revised reporting requirements will be:

> The marketable crude oil name (MCON) or other crude oil name designation, volume (in gal), and Country (or State) of origin for each crude oil supplied to the refinery during the annual compliance period.

Although we believe that the carbon intensity estimates would be improved by more extensive reporting, comments received to the proposal in the first 15-Day Notice requiring detailed information on MCON location and production data, raised issues and complexities associated with requiring regulated entities to provide such information. In response, with regard to field-specific production parameters, ARB will continue to collect crude oil recovery data from available, independent sources. Oil producers are also encouraged to supply data to ARB in order to help maintain a robust database.

B-34. Comment: We do oppose the company-specific and company-specific refinery specific approaches. Such methods will restrict the type of crudes that an individual refinery can process, potentially creating winners and losers and causing leakage. These approaches open the door to out-of-state markets by providing a loophole around crude carbon intensity accounting. It is very important to focus on how the regulation is implemented.

I think if you move away from what CARB staff is proposing today, the question of how to handle these materials that could come through the loophole—and the materials are the intermediates we run. This is non-crude raw materials. Some of the refineries in the state might run 20 percent of material that's not crude based. That's currently not accounted for in any of the approaches being discussed. It's not clear how that would be done on a hybrid approach either. That's one. We buy blend stocks. We might buy something and blend it into the gasoline we sell. That's not accounted for. There's no accounting of what crude was used to make that blend stock. And then the third piece is actual imports, finished products. Whether we bring them in or other companies bring them in, if the carbon intensity of the crude oil that's used to make those materials is not accounted for, that's a loophole that could penalize in-state refineries while not holding out-of-state or out-of-country refineries accountable. (CONOCO2)

Response: This comment argues against the adoption of the Hybrid California Average/Company Specific Approach and the Company Specific Approach. These are two of the six potential approaches for the treatment of crude oil considered by staff as discussed on pages 77-84 of the ISOR. Although we discussed the Hybrid and the Company Specific approaches, we did not recommend adoption of either the Hybrid or the Company Specific approaches and therefore this comment is really not germane to the regulatory amendments considered and approved by the Board.

We do, however, note that as part of our assessment of the alternative approaches, we sent out a survey to the petroleum companies participating in the LCFS, including the commenter. In the survey we requested data on a number of refinery feedstocks, including:

- Crude slates for 2008, 2009, and 2010;
- Imported intermediates and finished products; and
- HCICO versus non-HCICOs in crude slates.

We received responses from only a small minority of survey recipients. These responses did not provide us with a sufficient basis on which to perform an analysis of the economic impacts and regulatory effects of importing petroleum intermediates and finished products. The Board directed staff in Resolution 11-39 to evaluate and propose, as appropriate, a refinery-specific approach to crude oil CIs. We appreciate these comments related to future tasks.

B-35. Comment: We appreciate ARB recognizing issues with the "HCICO" approach in the existing LCFS regulation and proposing that all gasoline and diesel receive the same WTW carbon intensity regardless of crude type. However, we believe the "California Average approach does not fully address CARB staff's stated guiding principle *"d"* on page 81 of the "ISOR" regarding crude shuffling to other jurisdictions and designing a program that can be exported to other jurisdictions. Shell urges ARB to adopt a "Worldwide Average" approach to crude carbon intensity, because crudes are marketed, traded and used globally. Any potential increase in the carbon intensity of crude production could still be captured in periodically updating the world wide average for a given year versus the worldwide average in the 2010 baseline year to ensure that any increases are mitigated. (SHELL)

Response: While we agree that the Worldwide Average Approach would provide less incentive to shuffle crudes as compared to the California Average Approach, limiting the incentive to shuffle crudes is only one of four Key Guiding Principles used to evaluate alternative approaches. As described on page 81 if the ISOR, these principles are:

- Accurate accounting for emissions from production and transport of crude oil;
- Discouraging potential increases in emissions and ensure that increases that do occur are mitigated;
- Promoting innovation for emission reduction activities; and
- Avoiding or limiting incentives to use crude shuffling to generate credits, avoid deficits, or transfer GHG emissions to other jurisdictions to avoid regulation under the LCFS.

When evaluated in the context of all four guiding principles, the Worldwide Average Approach has significant drawbacks, which are discussed on page 83 of the ISOR. Based on this evaluation, we determined the California Average Approach to be the preferred alternative for amendments.

B-36. Comment: We appreciate that ARB staff strives to encourage innovation and investment in technology that will reduce the carbon intensity of fuels, including carbon capture and storage (CCS) technology and support the principle of regulated parties being able to earn LCFS credits if it obtains crude from sources that have implemented innovative methods such as CCS to reduce emissions for crude recovery. However, the proposed regulatory amendment includes a 5.00g$C0_2$e/MJ minimum threshold for the reduction in the carbon intensity for crude oil recovery (well to refinery entrance gate) to qualify for LCFS credits. We believe it is premature to include such a threshold value at this time. Such a threshold could actually act as a barrier to the developments of such projects and actually act to discourage work in this field. (SHELL)

Response: In the third 15-day revisions, staff refined the 5 gCO_2e/MJ minimum threshold value to 1.0 gCO_2e/MJ. We do not believe that this threshold will provide any additional barrier to development of emission reduction projects. Any improvement in the carbon intensity of a marketable crude will be captured in the calculation of the Annual Crude Average carbon intensity value. The innovative method provision only provides an additional incentive to use innovative methods that provide a substantial reduction in carbon intensity for crude production.

B-37. Comment: We believe the low carbon fuel standard requirements become infeasible within the 2014 to '15 time frame as we mentioned earlier. And incorporating the crude oil carbon intensity further exaggerates this problem. Crude differentiation will lead to crude shuffling. Canadian crude oil will not be disadvantaged to the world markets because of this legislation. It will be disadvantaged to one state because of this regulation, and that will be California. Essentially, the Canadian-type crudes will now transport to foreign markets, and they'll be replaced in California by foreign crudes that are imported into markets, resulting in increased global CO_2 emissions associated with transportation. (TESORO)

Response: While we agree that a "no crude differentiation approach" would provide less incentive to shuffle crudes as compared to the California Average Approach, limiting the incentive to shuffle crudes is only one of four Key Guiding Principles used to evaluate alternative approaches. As described on page 81 if the ISOR, these principles are:

- Provide accurate accounting for emissions from production and transport of crude oil;
- Discouraging potential increases in emissions and ensure that increases that do occur are mitigated;
- Promoting innovation for emission reduction activities; and
- Avoiding or limiting incentives to use crude shuffling to generate credits, avoid deficits, or transfer GHG emissions to other jurisdictions to avoid regulation under the LCFS.

When evaluated in the context of all four guiding principles, the "no crude differentiation approach" has significant drawbacks which are discussed on page 84 of the ISOR. Based on this evaluation, we determined the California Average Approach to be the preferred alternative for amendments. See response to comment B-15 for further discussion.

Furthermore, crude differentiation under the CA Average approach only discourages refiners from purchasing greater quantities of high-intensity crudes in the future than they purchased in the baseline year; it does not incentivize the shuffling of crudes already refined in California. Moreover, the Baseline Crude Average carbon intensity already accounts for a large quantity of high-intensity crudes, as greater than 20 percent of the crude oil supplied to California refineries was recovered using methods such as thermal enhanced oil recovery, oil sands mining, and/or upgrading to synthetic crude oil. In essence, crude differentiation within the context of the California Average Approach helps to maintain the “status quo,” which already includes a significant quantity of high intensity crude.

B-38. **Comment:** The current approach unnecessarily incentivizes refiners to process higher carbon intensity crude oils because the deficits incurred if/when the industry average exceeds the target baseline are then spread across the entire industry. Even those refiners who did not process any HCICO will be penalized in this approach since the deficits are spread across the entire refining industry, regardless of what each individual refinery actually processed.

The "average" refiner approach makes forecasting and budgeting for compliance nearly impossible since compliance hinges on the industry as a whole and not simply the efforts a company puts forth to comply.

Efficiencies and prudent business decisions, in line with the intent of the LCFS, should not be disadvantaged by using an "average" refiner approach. Kern does not object to the portion of the proposed amendment that establishes a baseline for the industry, but does object to compliance then being demonstrated by the entire industry as an average. Kern suggests that each refinery be assessed for compliance, and incur deficits as appropriate, on an individual basis. Alternatively, Kern suggests in lieu of individual compliance demonstrations, that certain exemptions be added to the current approach. Such exemptions could include the following ideas, or any combination thereof:

- Non-HClCO demonstration exemption: Provide an exemption to refiners that can demonstrated that no crude oil processed during the compliance year exceeded the established baseline carbon intensity.
- Low-volume processor exemption: Provide an exemption to refiners processing less than 5% of the state's total crude capacity from any deficits that would otherwise be incurred by industry average carbon intensity in excess of the established baseline. The basis for such an exemption lies in that small processors inherently have limited ability to affect the average carbon intensity, but conversely are easily affected by larger refiners’ decisions to process HCICO.
- Low-volume producer exemption: Provide an exemption to refiners producing less than 5% of the state's total primary refined products from any deficits that would otherwise be incurred by an industry average carbon intensity in excess of the established baseline. (KORC1, KORC2)

Response: We agree that the potential for a few refiners driving up the Annual Crude Average carbon intensity and incurring an incremental deficit that will be applied to all refiners is a disadvantage of the CA Average approach. The commenter recommends shifting to a Company Specific approach or allowing for some refiners to be exempted from the incremental deficit if they meet certain conditions. Although the Board approved the CA Average approach at the December 2011 hearing, they were sensitive to the points made in this comment and have asked staff to evaluate and propose, as appropriate, an option for individual regulated parties to have their deficits for gasoline and diesel determined on a refinery-specific basis that accounts for the carbon intensity of domestic and imported crude oils, intermediate products, and finished fuels.

We also understand commenter's concern that the approach may make forecasting and budgeting for compliance challenging, as each refinery does not control whether it incurs an incremental deficit or not. In response to this concern we are changing the calculation of the Annual Crude Average carbon intensity to a three-year rolling average. A three-year rolling average improves forecasting and significantly lessens the potential for refiners to be surprised by a large incremental deficit.

B-39. Comment: Insufficient data has been published to date communicating the carbon intensity values of specific domestic crude oil slates, specifically those crudes produced from individual production fields within the state of California. These carbon intensity values are key factors both in terms of refiners being able to assess the potential impacts of the proposed amendments at this time, as well as making strategic decisions about which crude oils should or should not be purchased in the coming years, where such decisions can still be influenced. Table 5 of CARBs October 2011 *Staff Report: Initial Statement of Reasons for Proposed Rulemaking* notes that the baseline crude average carbon intensity was derived using a crude oil mix comprised of nearly 40% crude produced within California. However, CARB has yet to publish or otherwise communicate carbon intensities of any specific California crudes that make up this significant piece of the total being processed within the state. (KORC1, KORC2)

Response: Working under contract with researchers at Stanford University, we have developed the Oil Production Greenhouse Gas Emissions Estimator (OPGEE), a lifecycle assessment model to be used to estimate carbon intensity values for crude oil production on a field-specific basis. As part of modifications proposed in the Third 15-day Change Notice, we have incorporated the OPGEE model and a Crude Oil Lookup Table into the regulation. The Crude Lookup Table lists carbon intensity values for all crudes supplied to California refineries during the baseline year of 2010.

B-40. Comment: As the program moves from a default scored basket to a statewide averaging approach, we entreat you to first do no harm to domestic production, which is an integral part of the California economy and currently responsible for nearly 40% of California's crude oil supply. More specifically we are concerned about the drive to abandon the California baseline average toward full differentiation of crude feedstocks. What this means practically is that we will have carbon intensity scores for domestic production based upon actual data, and carbon intensity scores for rest-of-world production that is either guesses or made up. This is less important under an averaging scheme than in a fully differentiated methodology, but in either case, domestically produced crude will suffer against imports based upon accurate scoring—or lack thereof and the buying behavior of regulated parties who will suffer costly deficits for taking in too much crude feedstock with higher carbon intensity scores will be negatively influenced.

Although CARB is attempting to answer this data gap by contracting with Acting Assistant Professor Adam Brandt of Stanford University to construct the Oil Production Greenhouse Gas Emissions Estimator (OPGEE), by its own admission the OPGEE scoping plan tells us there will be a tradeoff between accuracy and required data that will be addressed by presenting comprehensive default parameter values. We are told that all required inputs to the model will be assigned default values that can be left as is or changed to match the characteristics of a given oil field, or marketable crude oil blend. If only a limited amount of information is available for a given project, then most of the values will remain at defaults. In contrast, the scoping plan notes, *if detailed data are available, a **more accurate** emissions estimate can be generated.* OPGEE-where there is data there is accuracy; no data, no accuracy? So, under a fully differentiated construct using the Acting Assistant Professor's model domestic production, for which data is readily available, will be accurate and rest-of-world production will get default scores according to his own project scoping plan. This creates by definition an unleveled regulatory playing field for California crude oil production as opposed to imports from foreign nations such as Libya or Venezuela.

Referring back to one of the desired goals of the amendments under consideration, namely a more accurate accounting of carbon intensity, it is reasonable to construe from the foregoing that we are likely to achieve less accuracy from the current proposed amendments, not more. Moreover, we will move from a structure that gave domestic production a default score and required imports to score their carbon intensity to the inverse—a structure that gives imported crude default scores and requires our own state resources to accurately score their carbon intensity. This is backward. At a minimum, CIPA requests CARB address this issue to ensure California production is not disadvantaged from a reporting standpoint with foreign imports before adopting the final regulatory changes. (CIPA1, CIPA2)

Response: We agree that the lack of accurate data on crude production parameters for many imported crudes is a problem. We have explored options for obtaining this data from several data collection sources and have asked refiners and oil producers to supply this data. With regard to field-specific production parameters, ARB will continue to collect crude oil recovery data from the available, independent sources. Oil producers are also encouraged to supply data to ARB in order to help maintain a robust database.

Furthermore, crude differentiation under the CA Average approach only discourages refiners from purchasing greater quantities of high carbon intensity crudes in the future than they purchased in the baseline year; it does not incentivize the shuffling of crudes already refined in California. Moreover, the Baseline Crude Average carbon intensity already accounts for a large quantity of high carbon intensity crudes, as greater than 20 percent of the crude oil supplied to California refineries was recovered using methods such as thermal enhanced oil recovery, oil sands mining, and/or upgrading to synthetic crude oil.

B-41. Comment: Our comments throughout the LCFS process consistently have argued that the carbon intensity (CI) value for all petroleum-based fuels, including the non-conventional fuels, should be the same. As discussed in our prior comments, discrimination among petroleum-based fuels is not necessary to achieve the purposes of the AB 32 program and would in fact be counterproductive. It is not needed to control development of unconventional resources in California, as they are controlled directly by applicable state and federal laws and regulations. The primary effect would be to discourage imports to California of fuels derived from other unconventional resources in North America, such as oil sands in Canada or oil shale in the Western U.S. This would have an inflationary effect on fuel prices in California, as these cost effective North American fuels would not be available. The adverse economic impacts would affect low income citizens disproportionately, an effect that AB 32 expressly seeks to prevent. While the legislation states a goal of contributing to worldwide greenhouse gas reductions, a discriminatory LCFS would not assist in attaining that goal. Fuels barred from California would simply be sold elsewhere, to other states or foreign countries where controls may be more lax and emissions from fuel transportation increased. The California economy would suffer, but worldwide emissions would not be reduced and in some cases would be increased. This is precisely the situation that AB 32 and AB 1007 seek to avoid, in requiring a regulatory program "that is equitable, seeks to minimize costs and maximize total benefits," and "minimizes the economic costs to the state" (secs. 38562(b)(1), 43866(b)(2)). (CNAES)

Response: The commenter states that distinguishing between crudes on the basis of CI under the LCFS will likely lead to shuffling of crude rather than impact upstream production methods and will increase costs to California refiners and consumers. These objections apply generally to all alternative crude provisions that differentiate crudes based on emissions associated with recovery and transport, including the provisions appearing in section 95486(b)(2)(A)2 of the original LCFS regulation. Those original provisions have already been subject to an impact assessment, as part of the original public rulemaking process. As shown in the response to comment B-27, A comment calling for crude equivalency would have been within the scope of the initial rulemaking, but it is not within the scope of the current rulemaking .

The proposed amendments will reduce the incentive to shuffle crudes by not allowing refiners to earn incremental credits when the California Average crude CI decreases. Incremental deficits are earned, however, when the California Average rises. Please see the responses to 45-day comment B-31, and third 15-day comment VI-5 for a full discussion of this provision. This disincentive for increasing the average crude CI, combined with the lack of an opportunity to earn credits for decreasing that CI will create a regulatory environment that grants refiners the flexibility to alter their crude slates but to do so in a way that does not significantly alter their baseline crude slate CIs. Refiners are discouraged from increasing their slate CIs but are not allowed to earn credits shuffling low CI crudes into the state and higher CI crudes elsewhere.

The Initial Statement of Reasons for the current rulemaking concludes that assessing the incremental compliance cost impacts of the proposed amendments requires evaluations of the case in which the California Average CI is maintained, as well as the case in which the average CI rises. Although costs under each of these scenarios can be characterized, combining the two outcomes into a single estimate of the compliance cost of the amendments is difficult. In sum, however, compliance costs will be minimized by two factors:

- Adopting a 2010 baseline, which will produce a higher average CI than the previous 2006 baseline; and
- Under the original provisions, any purchase of an "out-of-basket" HCICO would generate a CI deficit that would have to be offset through the use lower CI fuels or the retirement of credits. Under the proposed amendments, however, the "basket" concept is done away with, and all crudes receive a specific CI. Some of will be lower than the CA average, making it possible to partially or wholly offset high-CI purchases with lower-CI crude purchases. Such offsets were not possible under the original provisions.

The increased flexibility made possible by these two aspects of the proposed California average approach indicate that the compliance costs of the amendments should be no higher than (and possibly even lower than) the compliance costs of the original provisions.

B-42. Comment: The current proposal appears carefully crafted to avoid charges of discrimination by foreign producers and to create apparent flexibility for refiners by:

- using a more recent and realistic baseline recognizing that so called "conventional" crudes are becoming more carbon intensive, while the non-conventional crudes are becoming less so;
- eliminating the discriminatory basket provisions and grandfathering of CA crudes;
- simplifying the requirement for complex reporting, including the HCICO method 2B that has been so long in development.

The Center supports each of these proposals as a step in the right direction. However, it does not appear that the proposal would eliminate the discrimination against unconventional crudes that permeates the current regulation.

The problem we see lies with the way the "jurisdictional average" CI apparently would be calculated. "Conventional" crudes are assigned a CI that approximates the type of production method plus a transportation allocation. All crudes with thermal production or high flaring automatically are given a CI of 20 g/MJ. The jurisdictional average is a weighted average of the percent production of conventional and high CI crude in that jurisdiction. This system continues to discriminate unfairly against some non-conventional crudes. For example, under this system Canada's rating for the purposes of calculating the CA average CI would be 18.43 g/mj—being 89% at 20 g/mj and 11% at 5.75 g/mj. In contrast, only about 50% of CA production is thermally produced and its conventional value is 4.38 g/mj. Accordingly, the jurisdictional average for CA crudes would be 12.08 g/mj—well below the Canadian value. Similarly, Venezuela, where the conventional CI is 6.54 g/mj, but 54% of production is thermal, would have a jurisdictional rating of 13.41.

These values, along with the percentage of each jurisdiction's contribution to the CA fuel pool, would be used to arrive at the CA weighted pool carbon intensity. In theory, the discrimination has been removed in that CA and Venezuelan crudes are not grandfathered. In practice, a substantial barrier would remain against use of non-conventional crudes from Canada and other jurisdictions. This would be true even though on a barrel for barrel basis the CI of each of the three crudes discussed above is very similar. For these reasons, we continue to believe that a single crude pool is the most effective and non-discriminatory approach, and that the true value of the LCFS lies not in the lifecycle emissions from crude supplies but in diversification of the transportation fuel mix in CA. (CNAES)

Response: The comment shows a misunderstanding of how carbon intensity values will be calculated under the amended crude oil provision. In determining the Annual Crude Average carbon intensity value, we will not be calculating country or jurisdictional average carbon intensity values as suggested in the comment, but rather we will calculate a carbon intensity value for every crude supplied to California refineries during a given year. The Annual Crude Average carbon intensity will then be calculated using a volume weighted average of the carbon intensity values for the crudes. See also the response to comment B-15.

B-43. Comment: Finally, the California LCFS discriminates against Canadian oil imports. Canada is the United States' largest trading partner and accounts for about 20 percent of U.S. oil imports. Oil imports from our democratic, friendly neighbor help boost our nation's energy security and are substantially discounted against world oil prices. The High Carbon Intensity Crude Oil designation is specifically designed to penalize the importation of crude oil slates that are higher in carbon intensity, but does not penalize the use of high-carbon crudes that are produced in California—a clear violation of the Constitution. (FORMLETTER4)

Response: This comment shows a misunderstanding of the amendments to the crude oil provision. The California Average approach does not distinguish between High Carbon Intensity Crude Oil (HCICO) and non-HCICO. In fact, the term HCICO is no longer part of the amended crude oil provision in the LCFS. Under the California Average approach each crude oil, whether produced inside or outside of California, will be assigned a unique carbon intensity value based on the specific practices used to recover and transport the crude to California refineries. The Annual Crude Average carbon intensity will then be calculated using a volume-weighted average of the carbon intensity values for the individual crudes. The CA Average approach ensures a consistent treatment of all crudes.

B-44. Comment: How did CARB calculate the CI value assigned to thermally enhanced oil recovery (TEOR), mining, and upgrading? How was the percentage of TEOR, mining, and upgraded crude oil calculated for Canada? It is unclear how assignment relating to TEOR mining and upgrading, (20 gCO_2/MJ) was calculated. Additionally, the regulation may be assuming that all heavy crude oil from Canada is derived from the oil sands. However, 11 percent of Canada's oil sands crude production is "cold production." (NRC)

CAPP is unclear on the calculations applied to Canadian crudes as the proposed approach uses production averages for Canada that are not representative of the actual Canadian production mix which today includes close to half from conventional oil and half from the oil sands. The relative weight of thermally enhanced oil recovery (TEOR), mining and upgrading is higher than the actual value. For example, the regulation appears to value all heavy crude as derived from TEOR methods, whereas 11 percent of oil sands crude is in fact "cold production" that does not use TEOR. In addition, it appears that the regulation includes upgrading in the CI valuation for oil sands crude, but does not include upgrading for conventional heavy crudes. (CAPP)

Response: ARB (along with Adam Brandt of Stanford University) has developed a life cycle analysis (LCA) model to use in estimating the CI intensity of crude production using field-specific data inputs. The LCA tool takes into consideration all components of crude oil production, including upgrading, regardless of crude oil origin. As part of the Third 15-day Change Notice, we updated the Baseline Crude Average carbon intensity value to the year 2010 using this tool and incorporated into the regulation a Lookup Table with carbon intensity values for individual crudes. The California baseline average crude CI is based on the carbon intensities of all crudes supplied to California refineries and their relative percentages, so that Canadian crude that is not derived from oil sands is proportionally represented in the CA average crude oil carbon intensity. We welcome information on the composition of MCONs and field-specific data input from all stakeholders in order to improve upon these carbon intensity estimates.

B-45. Comment: Why does the LCFS include upgrading in the CI determination for oil sands crude and not for conventional heavy crudes? Upgrading takes place with all heavy crudes either in standalone facilities or integrated refineries with upgrading capacity. Given this, oil sands crude and other heavy crudes would have similar CIs for this stage. (NRC)

Response: For those marketable crudes where upgrading occurs prior to transporting the crude to the California refinery, emissions from upgrading will be included in the CI of crude oil production. The OPGEE model, which was incorporated into the amended regulation in the Third 15-day Change Notice, takes into consideration all components of crude oil production, including upgrading, regardless of crude oil origin.

B-46. Comment: Are the proposed baseline CI values and "Lookup Tables" an interim methodology in place until Adam Brandt's life cycle assessment (LCA) tool is finalized? We understand that CARB has contracted Adam Brandt to develop an LCA tool to evaluate all crudes consumed in California using consistent criteria. Canada is concerned that if implementation is delayed, then the relatively imprecise values under the interim approach could persist over the longer term. (NRC, CGC1, CGC2)

Response: Yes, included in the Third 15-day Change Notice is an update to the Baseline Crude Average carbon intensity value to the year 2010 using the OPGEE model developed by Adam Brandt.

B-47. Comment: How will the designated Executive Officer determine: (i) if a fuel's CI is higher than the Lookup Table value, and (ii) whether a new pathway is required? In order to determine incremental deficits resulting from failure to meet the State's GHG reduction targets, regulated parties must calculate the CI of their fuels. Treatment of higher GHG emitting fuels is somewhat uncertain, given that California's LCFS implementing measure was set up to deal with lighter fuels. (NRC)

Response: The calculation of carbon intensity values under the LCFS is not limited to lighter fuels, but includes all fuels. Some of the pathway carbon intensity values in the lookup tables have carbon intensity values greater than the values for gasoline and diesel. The regulated party must supply information sufficient to determine which of the pathway values is most appropriate for the specific fuel or develop a new pathway carbon intensity value if none of the lookup table values are representative.

B-48. Comment: CAPP has reviewed the low Carbon Fuel Standard 2011 Program Review Report and with special interest, the chapter covering the treatment of High Carbon Intensity Crude Oil (HCICO). We understand that several alternative approaches to HCICOs were considered and that the California Air Resources Board (CARB) proposes a "California Average Approach." CAPP understands that this approach will calculate the average Carbon Intensity (CI) of crudes in the California basket on an annual basis and compare it with the baseline year. This approach is intended to deal with any increases in the share of high CI crude oils used in the state by requiring companies to make proportionate reductions should the average CI increase. (CAPP)

Response: We agree that the LCFS will calculate the average Carbon Intensity (CI) of crudes used in California on an annual basis and compare it with the baseline year. The California average approach is intended to deal with any increases in the CI of crude oils used in the state by requiring companies to make proportionate reductions should the average CI increase.

B-49. Comment: We appreciate that the specific treatment of oil sands crude as a HCICO has been removed, to the best of our understanding, but continue to believe that the appropriate treatment for crude oils in an LCFS is to maintain a single carbon intensity value for all crude sources. A significant issue is how to transparently and accurately calculate the carbon intensity value of other crude sources. The fact that there is a broad range of possible intensities associated with the production and transportation of crude oil, and the methods to determine these intensities are not applied consistently results in an apples-to-oranges comparison of GHG emissions intensities. For example, boundary definitions, allocation type and treatment of inputs within the life cycle analysis may vary depending on the study and methodology. (CAPP, CGC1, CGC2)

Response: We agree that there is a broad range of possible carbon intensities associated with the recovery and transportation of crude oil. Treating all of these crude oils as equals would ignore these differences. Together with Adam Brandt of Stanford University we developed an LCA tool for crude oil recovery and transport which will be used to standardize the estimation of crude carbon intensity values under the LCFS. The LCA incorporates field-specific data inputs for crude oil production and allows for the direct comparison of CIs for crude oil production. Please also see responses to comments B-15.

B-50. Comment: CAPP questions how CARB intends to collect and verify the CI data from all jurisdictions. While the Canadian oil and gas industry provides transparent and verifiable CI data, many other jurisdictions do not. The absence of credible and verifiable data on emissions associated with their production creates the risk of inaccurate calculation of life cycle values. As a minimum, should CARB continue to pursue differentiation of crude sources, CAPP believes it is imperative that CARB develop a measure that requires a high level of transparency in reporting CI data and provides a clear penalty for those jurisdictions that do not. (CAPP, CGC1, CGC2, NRC)

Response: We will continue to collect crude oil recovery data on a field-level basis from numerous independent sources. Oil producers are also encouraged to supply data to ARB in order to help maintain a robust database. If field-level data cannot be obtained and are not provided by producers, we intend to develop values for parameters when estimating the carbon intensity for these crudes based on available information and within the range observed worldwide. Producers who do not believe that these defaults accurately represent their crude production will again be encouraged to provide ARB with complete and accurate data. It is to be noted that although different crudes will have different CI values, the ARB average approach will be based on a statewide average CI value that will be applied for all gasoline and diesel sold in California.

B-51. Comment: An ongoing concern for CAPP is the persistent lack of recognition for existing carbon management systems, leading to duplication of policy. CAPP believes that emissions should be managed in the jurisdiction in which they occur. In the Canadian context, we would draw CARB' s attention to the existing Alberta regulation that places a clear and unambiguous price on carbon emissions. (CAPP, CGC1, CGC2, NRC)

Response: The LCFS is designed to account for actual emissions associated with fuel production. To the extent that carbon management systems and carbon prices result in actual reductions in emissions during crude oil recovery and transport, they will be included in calculation of carbon intensity values. Carbon intensity values for marketable crudes will be updated periodically to reflect improvements in crude oil production. The amended regulation will also allow for LCFS credits to be earned for innovative crude recovery methods that have occurred during or after 2010.

B-52. Comment: CAPP commends California for addressing GHG emissions reduction policy, but strongly urges a reconsideration of the policy details. CAPP is emphasizing that treating all crude oils equally reduces the risk of unforeseen consequences, such as crude shuffling and the associated increase in overall GHG emissions, and will result in a better, more streamlined and administratively simpler, policy. We appreciate the opportunity to provide these comments and look forward to continuing engagement on these issues. (CAPP)

Response: Please see response to comment B-15.

B-53. Comment: We will continue to follow this process to ensure that the LCFS treats all crudes fairly, based on their actual GHG emissions, and that fuel derived from Canadian crude is not treated in a manner that is inconsistent with the United States' international trade obligations. (CGC1)

Response: The LCFS is designed to produce actual reductions in GHG emissions. The OPGEE model, incorporated into the LCFS regulation in the Third 15-day Change Notice, used for estimating carbon intensity values for crude production and transport uses a consistent approach for all crudes based on oil production characteristics. We will treat all crudes in an equivalent manner based on their actual carbon intensities.

B-54. Comment: We await clarification on what carbon intensity values will be used until the life cycle assessment tool is finalized and if a supplemental regulatory advisory will be issued for the 2012 calendar year. (CGC2)

Response:

ARB under contract with Adam Brandt of Stanford University has developed a life cycle analysis (LCA) model to use in estimating the CI intensity of crude production using field-specific data inputs. As part of the Third 15-day Change Notice, we used this tool to update the Baseline Crude Average carbon intensity value to the year 2010 and incorporate into the regulation a Lookup Table with carbon intensity values for individual crudes. Please also refer to ARB Regulatory Advisory 10-04B for additional information.

B-55. Comment: Have all references to the High Carbon Intensity Crude Oil (HClCO) provision been removed from the proposed amendments to the LCFS? While all reference to the HCICO provision appear to have been removed from the LCFS, recent correspondence from CARB has continued to use the term HClCO in the context of the revised LCFS. (NRC)

Response: The term “high carbon intensity crude oil” (HCICO) will not be used in the LCFS.

B-56. Comment: Questions remain about how the LCFS will be implemented, and whether some crudes could receive less preferential treatment under this approach. (CGC1)

Response: The LCFS is designed to produce actual reductions in GHG emissions and will treat all crudes in equivalent manner based on their estimated CI values.

B-57. Comment: The AEC supports proper accounting for the incremental carbon deficits from the use of High Carbon Intensity Crude Oil (HClCO). Proper accounting for all gasoline and diesel substitute pathways is critical to the development of low carbon fuels for several reasons. First, the underlying premise of the LCFS is that it scores different fuels coming into the marketplace based on their full lifecycle carbon intensity *value* (CI *value*). One of the primary reasons a performance standard is useful is it provides a predictable framework for investment *over* time by allowing investors to react to market trends, assess *value* within the overlying LCFS regulation, and invest accordingly. HCICO is a significant and quickly increasing percentage of California's crude oil slate. According to recent reports presented to CARB, the carbon intensity of producing and transporting crude oil in California increased by 20 percent in the last four years alone. If the actual CI *values* of HCICO pathways are not properly accounted for, there will be an unnecessary disconnect between actual market performance and the performance predicted by the LCFS. While it is impossible for any regulation to be perfect with regard to reflecting actual CI *values* in the marketplace, improper accounting for HCICO has the potential to create *very* large disconnects between the emerging marketplace and the regulation, which in turn will reduce the predictability of the program and increase investment risk. Second, as a matter of consistency, the LCFS requires detailed documentation and regulatory accountability from the point of origin of the biofuel feedstock through the production process and path to market. We believe the LCFS should eliminate, to the greatest degree possible, any compliance inequities that exist among the many compliance fuels relative to petroleum-based fuels, and seek to define "performance" consistently across all fuel pathways. Third, if refiners are allowed to utilize increasing volumes of HCICO without penalty, the effect will be the creation of a carbon "black box" that, if current trends continue, could greatly offset the actual carbon reductions achieved by the LCFS. This outcome could jeopardize both the effectiveness and credibility of the program here and abroad. The amendments proposed to §95486 are certainly a step in the right direction, but it is unclear why individual bio-refineries are held accountable for individual fuel pathways from cradle to grave, but individual petroleum refineries are not. We encourage CARB staff to tighten the HCICO provisions commensurate with the protocols established for bio-based fuels under the regulation. (AEC)

Response: The major points made in this comment are that ARB should require greater reporting of data necessary to estimate carbon intensity values for crude oil production and employ a refinery-specific accounting methodology rather than a California average approach.

Although the Board approved the California Average approach at the December 2011 hearing, the Board was sensitive to the points made in these comments and asked staff to evaluate and propose, as appropriate, as part of a future rulemaking, an option for individual regulated parties to have their deficits for gasoline and diesel determined on a refinery-specific basis that accounts for the carbon intensity of domestic and imported crude oils, intermediate products, and finished fuels.

In the third 15-day Change Notice we have proposed limiting the reporting requirements for crude oil. The revised reporting requirements will be:

> The marketable crude oil name (MCON) or other crude oil name designation, volume (in gal), and Country (or State) of origin for each crude oil supplied to the refinery during the annual compliance period.

Although we agree that the carbon intensity estimates would be improved by more extensive reporting, commenters to the proposal in the first 15-day Notice requiring detailed information on MCON location and production data, raised issues and complexities associated with requiring regulated entities to provide such information. With regard to field-specific production parameters, ARB will continue to collect crude oil recovery data from numerous available, independent sources. Oil producers are also encouraged to supply data to ARB in order to help maintain a robust database.

B-58. Comment: So I really think each of them needs to be analyzed further and their impacts really looked at as we really go forward and decide which option this Board decides to choose. (WSPA3)

B-59. Comment: I don't think it's a simple answer. And I'm not trying to be evasive. I do think it really does deserve further analysis in the context of the whole picture.

And if we had enough time to continue doing that—I know we've been looking at it for a long time. I'm not saying we haven't invested a long time looking at it. (WSPA3)

B-60. Comment: So I really think both options, whether it's any of the other options that are in there, you know, California average, all those need to be looked at fully in the context of what the impacts will be to the transportation system as well. (WSPA3)

Response: These comments provide information related to the amendments proposed in this rulemaking. Because they are outside the scope of the 45-day Notice, no response is required.

C. Electricity Regulated Party Provisions

This section contains comments specifically related to the electricity regulated party provisions of the LCFS. This includes comments pertaining to regulated party designations, requirements, and overall provisions.

C-1. Comment: As currently written, CARB's LCFS program for regulated parties for electricity cannot be implemented as drafted and must be revised to remain consistent with the regulatory and legislative direction established for California. The California Public Utilities Commission, the State Legislature and the Governor have all implemented public policy measures supporting a competitive market in which third party EV charging providers are both customers of the regulated utilities and also customer facing entities connected with the grid. (ECOTALITY1)

Response: We disagree. The California Public Utilities Commission (CPUC) ruled in the Phase 1 decision of their Alternative Fueled Vehicle Proceeding (Rulemaking 09-08-009) that Electric Vehicle Service Providers (EVSP) are not utilities, and therefore the CPUC does not have regulatory authority over them. As a result, EVSPs are considered customers of utilities. Assembly Bill 631 (Ma, Stats. 2011, ch. 480) codified the Phase 1 decision. Subsequently, in the Phase 2 decision of Rulemaking 09-08-009, the CPUC ruled that in most cases Investor Owned Utilities cannot own Electric Vehicle Servicing Equipment, in part because utility ownership could result in competitive limitations.

As provided in oral testimony at the December 2011 Board hearing, CPUC staff agrees with the Board that the LCFS amendments are consistent with the CPUC Phase 1 and Phase 2 decisions, and with Assembly Bill 631. Moreover, the amendments will not result in competitive disadvantages for EVSPs because the amendments require all LCFS credit revenue to benefit electric vehicle customers, and as customers of utilities, EVSPs will benefit directly from the revenue utilities receive from LCFS credits.

C-2. Comment: It is imperative that CARB's LCFS regulatory framework aligns with the CPUC and legislative direction, ensuring that LCFS program implementation is consistent with creating a competitive EV market in California. (ECOTALITY1)

Response: The amendments allow credits to be earned by Electrical Distribution Utilities (EDU) for residential transportation electricity and by third party Electric Vehicle Service Providers (EVSP) for transportation electricity supplied through public access equipment. This designation provides the framework for regulated parties to return credit proceeds to EV customers as required by the amendments in an efficient and logical manner. EDUs have the ability to use credit proceeds to benefit EV owners by, for example, lowering rates for residential electricity used for transportation. Many EDUs plan to use credit proceeds in this manner. Therefore, the amended regulation's designation of regulated parties supports a competitive EV market in California. (See also response to Comment C-1.)

C-3. Comment: As a result of current regulatory and legislative policy, the role of IOUs in EV charging services is limited for the purposes of charging its own fleet and workplace charging for employees. This needs to be reflected in the LCFS program. Third party providers who manage smart EVSE networks should be eligible to become regulated parties for residential, fleet and workplace charging in addition to commercial and public locations. The submetering infrastructure required to measure electricity for LCFS purposes will *not* be owned by the utilities. Instead, customers and third party providers will own submeters in the EVSE and will therefore be in the best position to collect LCFS credits as prescribed by CARB. (ECOTALITY1)

C-4. Comment: In the case of utilities ownership, collecting LCFS credits is likely to require the end use customers, particularly in residential, to install an expensive second meter, which increase the overall cost of EV adoption. (ECOTALITY)

C-5. Comment: Staff stated that an LCFS objective was to promote all fuel use. Unfortunately, giving residential charging credits to utilities may have exactly the opposite effect. Utilities have to install a second meter to collect those credits. The installation of that second meter from our experience in California costs anywhere from 500 to several thousand dollars. That obviously is a major impediment to someone adopting an EV. With our equipment, it's already built in. There is no additional cost to the consumer to collect that data. (ECOTALITY3)

Response: Currently, for residential EV charging, electricity is being measured by utility-owned second meters in some EV residences and by submeters embedded in Electric Vehicle Supply Equipment (EVSE) owned by a third-party EVSP in other residences. For public charging, electricity is measured in many cases by EVSP-owned submeters. Residential customers who have opted to have a second utility meter installed have done so to receive an EV rate schedule that encourages off-peak charging and may result in lower charging costs. In some cases, second utility meters have been costly to install and operate, and may be redundant in cases where a submeter is available to measure electricity.

To address the issues of meter redundancy and cost, the CPUC is currently considering a submeter protocol to allow submeters to be used to bill residential EV load, avoiding second meter installation. Utilities are currently in the early stages of their joint protocol development plan, and completion of a submetering protocol is expected to be filed in summer 2013. If this protocol is implemented, it should be a cost savings for EV customers who no longer need to install a second utility meter to receive the EV rate schedule.

C-6. **Comment:** Where EVSPs are customers of the utility, they should be able to self-select to become regulated parties. Where EVSPs are not customers of the utility but do provide a service to a utility customer, then the utility customer should be able to opt for the EVSP to be the entity collecting LCFS credits on their behalf as a regulated party. This will eliminate any confusion on who is the eligible entity and minimize the administrative complexity in the program. (ECOTALITY1)

Response: Under the amended regulation, EVSPs are regulated parties in cases where they have installed public charging services. While EVSPs are not regulated parties for residential charging, when operating in the residential context as utility customers, they will receive full value of the credits awarded to utilities as required by the amendments. We believe allowing utility customers to select regulated parties for the electricity they use for EV charging would be cumbersome, confusing, and difficult to implement.

C-7. **Comment:** Utilities should only be eligible as default regulated entity where the customer elects the utility or where neither the customer nor the third party has otherwise elected to become a regulated entity. (ECOTALITY)

Response: To maximize the number of credits captured by regulated parties, the amendments include provisions that identify default regulated parties that can opt-in to claim LCFS credits in cases where the initially intended regulated party does not meet regulation obligations, goes out of business, does not have interest in being a regulated party, or otherwise cannot be located. In such cases, the logical default regulated party is the local utility because, as public entities, their operations are relatively stable and participation in the LCFS program in future years is highly likely. It is not necessary for the EV customer to elect a default regulated party, and asking EV customers to elect regulated parties would be difficult to implement.

C-8. **Comment:** In response to CARB's current definition of regulated parties for electricity, the Coalition is recommending the following modifications: In the case where utilities own and operate smart grid enabled EVSE [electric vehicle service equipment] in their service territory, the utility would become the default regulated party. (ECOTALITY)

Response: Investor Owned Utilities (IOUs) are prohibited by the CPUC from owning EVSE. However, other utilities (such as Publicly Owned Utilities (POU) and municipalities), EVSP, and EV customers may own EVSE. To establish regulated party designations based on EVSE ownership would increase the number of regulated parties and require a greater amount of ARB resources to validate credit ownership and use of credit revenue. The modified regulation designates regulated parties in the amendments to minimize ambiguity and simplify the process of reporting and earning credits.

C-9. Comment: Our companies have and will promote the use of electric vehicles and associated fueling infrastructure, develop products to increase the utilization of electric transportation, with its concomitant increase in LCFS credits, and operate an integrated charging network that incorporates both residential and public charging in a seamless infrastructure grid. Simply providing electricity has not and will not promote electric transportation nor maximize credits for the LCFS program. (ECOTALITY1)

Response: We disagree. Utilities, as the providers of electricity, are in the best position to offer EV customers lower electricity rates. It is anticipated that utilities will, in many cases, use credit revenue to keep EV electricity rates low.

C-10. Comment: The program should be structured to encourage and allow entities investing in infrastructure to utilize the value of the LCFS credits toward re-investment in the infrastructure and/or pass-through directly to the end-use customer minus administrative costs incurred by the regulated party. This will ensure that the LCFS credits maximize future impact on EV adoption. (ECOTALITY1)

C-11. Comment: As currently drafted, the proposed language does not recognize the innovation and technology advancements of EVSE manufacturers like Better Place, Coulomb and ECOtality, including the ability to sub-meter and calculate the credits independent of the utility system. (ECOTALITY1)

C-12. Comment: To maximize the LCFS program, it is imperative that CARB staff implement a program consistent with current California regulatory and legislative policy and acknowledges the technological innovation, benefits and role third party infrastructure providers are playing in enabling optimal energy consumption to support usage of electric vehicles. (ECOTALITY1)

C-13. Comment: Proposing utilities as the only default party able to “opt in” to the credits negates the fact of the valued innovation and investment being introduced to the EV charging services market by our companies. (ECOTALITY1)

C-14. Comment: The proposed regulation for regulated parties for electricity should recognize contractual relationships and that charging providers are installing smart infrastructure. Third party providers who meet these criteria should be eligible to collect residential and commercial credits as well as act as default parties eligible to "opt in" for credits for workplace and fleet customers. (ECOTALITY1)

Response: Entities such as Better Place, Coulomb, and ECOtality have the ability under the amended regulation to use their submeters to report for credits for public charging. For residential charging, we believe utilities are in a better position to return credit value to EV customers by keeping electricity rates low or through other customer benefits.

C-15. Comment: I encourage the Board to direct the staff to reconsider the amendments and look very hard at its exclusion of EVSPs from residential and commercial charging. (ECOTALITY3)

Response: Exclusion of EVSPs from residential, fleet, and workplace charging is well justified because utilities are in the best position to return credit value to EV customers for residential charging. For fleet and employee charging, rewarding fleet owners and employers for establishing charging services is the best way to promote EV market growth.

C-16. Comment: The owner/operator of the smart grid enabled electric vehicle charging equipment (EVSE) should be able to monetize and apply LCFS credits to the EV cost of ownership less the administrative and operations costs incurred by the regulated party. (ECOTALITY)

Response: Under the amendments, the EVSP who has installed public charging must use all credit proceeds as direct benefits for current EV customers. It is reasonable to assume that regulated parties may need to use some credit revenue to cover administrative and operations costs of acquiring credits and returning their value to customers. However, as required by the amended regulation, regulated parties must account for these costs in annual reports to the ARB.

C-17. Comment: To qualify for commercial/public credits, where the utility owns and operates public smart grid enabled EVSE, the utility should be required to utilize LCFS credits collected to offset costs of public charging to all EV customers to encourage its use and ensure a level playing field in the market. (ECOTALITY1)

Response: Where a utility is either a regulated party or has been approved by the Executive Officer (EO) as default regulated party for public charging, the utility is required by the 2011 amendments to use all credit proceeds as direct benefits for current EV customers.

C-18. Comment: Although not discussed in detail here, the SFPUC also reiterates the recommendation in our prior comments that the LCFS regulations should retain the provisions that allow for carbon intensities for electricity to reflect the supplier's specific resource mix and resulting carbon content. (SCEC)

Response: Fuel pathway development under the LCFS has followed the pattern established in Argonne National Laboratory's GREET model: the CI associated with electrical energy consumption reflects the mix of energy used to generate electricity on the regional level. The use of a regional energy mix is necessary in staff-developed pathways, which are meant to be applicable over a wide geographical area. Most Method 2 applicants are also comfortable using the applicable CA-GREET regional energy mix. Departing from this well-established pattern would create a significant problem for staff: each time a new pathway bases its electrical energy CI on a sub-regional (e.g., utility-specific) energy mix, that sub-region is effectively been removed from the regional mix. Once that happens, staff is faced with the job of (a) re-calculating the regional electrical energy CI, and (b) recalculating the CIs of all pathways based on that regional CI. The only alternative would be to require all future pathways to be calculated, and all past pathways to be recalculated, using sub-regional electrical energy CIs. Neither of these alternatives is feasible at this time.

C-19. Comment: The definition of "Regulated Parties" should be modified to allow Community Choice Aggregators, together with all Load Serving Entities (LSEs) to earn LCFS credits. The LCFS mandates a decrease in the carbon content of transportation fuels used in California. For this mandate to be achieved, the state must increase its reliance on low-carbon fuel supplies, including electricity supplies, in lieu of petroleum fuels for transportation. As a result, the ARB should ensure that all suppliers who provide low carbon electricity directly to transportation end uses should be eligible and have priority to earn LCFS credits as "regulated parties." Current regulations allow electric utilities that provide distribution (delivery) of electricity supplies to their customers to participate in the LCFS program as "regulated parties" able to earn" credits and, in specific circumstances, to have priority over other entities along the delivery chain. This is appropriate in instances where the distribution utility is also the electricity supplier, as the entire framework of the LCFS program is for participants to earn credits (or accrue deficits) based on the carbon content of the fuel that is supplied/consumed for transportation. However, as drafted, amongst electricity suppliers, the regulations limit the definition of eligible "regulated parties" to "Electrical Distribution Utilities" (EDU), thus excluding those circumstances where customers choose to purchase their electricity supplies from a supplier who is not the customer's distribution utility—for example, when a customer chooses to purchase electricity supplies from a Community Choice Aggregator (CCA), or an electricity service provider. In these instances, eligibility and "regulated party" status defaults to the distribution utility, who has no role in, or cost responsibility for, the carbon content of the fuel that is being provided: Precluding suppliers and end-users that choose this path of delivery from participation in the LCFS is inequitable and should be corrected. (SFPUC)

C-20. Comment: Finally, in addition to expanding the EDU definition, the SFPUC urges the ARB to develop a hierarchy of eligibility for LCFS credits that recognizes the importance of the role played by the electricity suppliers in reducing carbon emissions, and gives opt-in priority to those entities. This hierarchy could allow distributors who are not suppliers to opt-in should the electricity supplier choose not to participate or not be fully compliant. (SFPUC)

Response: Community Choice Aggregators (CCA) are not Electricity Distribution Utilities and as such do not qualify to earn LCFS credits for transportation electricity. Because CCA share distribution infrastructure with utilities, it may not be clear that the electricity generated by the CCA is in fact supplying EV charging equipment. One goal in preparing the amendments was to eliminate ambiguity in some regulated party designations. We believe the regulated party designations in the amendments will minimize confusion in awarding credits. However, we will continue to work with interested stakeholders to explore this issue.

C-21. Comment: WSPA requests the following wording be deleted/added as follows, in strikeout/underline format:

(B) For transportation fuel supplied through public access EV charging equipment, the third-party non-utility Electric Vehicle Service Provider (EVSP) or Electrical Distribution Utility that has installed the equipment, or ~~had~~ an agent that has installed the equipment and who has a contract with the property owner or lessee where the equipment is located to maintain or otherwise service the charging equipment, is eligible to opt-in as the regulated party.

(C) For transportation fuel supplied to a fleet of three or more EVs, a company operating a fleet (fleet operator), or its contractually designated agent, is eligible to be a regulated party. If the fleet operator is not the regulated party for a specific volume of fuel or has not otherwise fully complied with the requirements of this subarticle, the Electrical Distribution Utility is eligible to opt-in as the regulated party with EO approval. For transportation fuel supplied to a fleet of less than three EVs, the Electrical Distribution Utility is eligible to be the regulated party. To receive credit for transportation fuel supplied to an EV fleet, the regulated party must include in annual compliance reporting an accounting of the number of EVs in the fleet.

(D) For transportation fuel supplied through private access EV charging equipment at a business or workplace, the business owner, or its contractually designated agent, is eligible to be a regulated party. If the business owner is not the regulated party for a specific volume of fuel, or has not fully complied with the requirements of this subarticle, the Electrical Distribution Utility is eligible to opt-in as the regulated party with EO approval. (WSPA2)

Response: The amendments proposed by the commenter designate regulated parties for electricity based in part on their ability to promote EV market growth in California.

We decline to adopt the suggested amendments, because designating agents to receive credits will not retain this intended goal of the program.

C-22. Comment: NRDC respectfully disagrees with the Staff Report's rationale for the designation of electric utilities as regulated parties. Improving the economics of vehicle electrification is sufficient justification for the designation of electric utilities as regulated parties. The ISOR provides, as justification for designation of electric utilities as regulated parties, the assertion that electric utilities will incur substantial costs associated with integrating vehicle charging. As a preliminary matter, it is premature to state that vehicle charging will result in net-costs to utility customers. As noted in CPUC Decision 11-07-029, the greater asset utilization that will result from off-peak vehicle charging could reduce the marginal cost of electricity for all utility customers, a net-benefit to the system. At this nascent stage in the development of the electric vehicle market, it is impossible to predict whether vehicle integration will result in net-costs or net-benefits. In fact, it is the goal of the CPUC to implement the policies which will ensure that vehicle electrification results in net-benefits. Accordingly, ARB's determination to allocate LCFS credits to utilities should not be based on supposition that vehicle integration will result in net-costs, when the opposite is equally possible. (NRDC2)

C-23. Comment: The "Final Statement of Reasons" should note the fact that improving the economics of vehicle electrification furthers the goal of maintaining the relevancy of the LCFS. (NRDC2)

C-24. Comment: NRDC respectfully request that the "Final Statement of Reasons" not justify the allocation of LCFS credits to utilities on the grounds that costs will be incurred to accommodate vehicle charging. Rather, ARB should justify its allocation to utilities on the grounds that they are providing a low carbon transportation fuel and are obliged to return all credit proceeds to EV customers. In sum, ARB should justify its regulations on the grounds that they could improve the economics of vehicle electrification and further the overarching goal of the LCFS - to increase the use of low carbon transportation fuels. No further justification is necessary. (NRDC2)

Response: We agree with NRDC's position that it is too soon to assume that vehicle electrification will result in net costs to utilities. We also agree that designating utilities as regulated parties will result in lower EV operating costs as credit revenue is required to be returned to EV customers.

C-25. Comment: Secondly, the ISOR mischaracterizes CPUC policy with respect to cost recovery, stating that all costs associated with vehicle integration will be subject to Decision 11-07-029's determination that, until 2013, costs in excess of utility allowances shall be treated as common facility costs. That aspect of Decision 11-07-029 speaks only to a very rare set of factual circumstances irrelevant to the majority of costs associated with vehicle integration. This is the only instance in which the Commission determined to treat cost recovery with respect to electric vehicles differently that cost recovery associated with any other load. The Commission justified this exception on the legislative directive included in California Public Utilities Code §740.2, AB 32 goals, and ARB's Scoping Plan which are intended to encourage the use of electricity as a transportation fuel. For the vast majority costs associated with vehicle integration, the standard cost allocation framework will apply. ARB should not cite to the exception to the rule to justify its allocation of LCFS credits to utilities. (NRDC2)

C-26. Comment: Thirdly, and most importantly, the justification for the allocation of LCFS credits to utilities on the grounds that they will incur expenses associated with vehicle integration is at odds with the Proposed Amendments' requirement that *all* credit proceeds be returned to *EV* customers. Section 95484(a)(6)(A)(l) does not allow for the use of credit proceeds to offset costs associated with vehicle integration. This is consistent with the existing cost allocation framework established by the CPUC. The costs of shared distribution equipment necessary to serve load are shared within any given customer class. Transformers do not discriminate between dishwashers and electric vehicles. The Proposed Amendments are consistent with CPUC policy, but the ISOR implies a different arrangement would be appropriate. (NRDC2)

Response: We acknowledge CPUC’s Phase 2 decision for Rulemaking 09-09-009 and agree with commenter’s position. Our intent as reflected in the requirement stated in the adopted amendments is that all credit revenue to be returned to EV customers. We do not intend that LCFS credits may be used by utilities to offset costs associated with vehicle integration. However, as the commenter correctly states, the adopted requirement does not conflict with CPUC’s Phase 2 decision for Rulemaking 09-09-009 that the costs of shared distribution equipment are to be met within a given customer class. EV owners will not be required to pay for equipment necessary for the increased load due to EVs alone.

C-27. Comment: EDUs are critical stakeholders in the long-term EV market and will maintain relevancy in the growing EV market by continuing to provide value in the future. SCE disagrees with CARB staff that allocating LCFS credits to utilities in all market segments does not further the goal of "maintaining relevancy." As discussed below, EDUs are relevant in many ways as either the primary regulated party in the residential market segment or the alternate regulated party in the fleet, workplace, and public-access market segments. As the primary distributor and deliverer of electricity for use as a transportation fuel, EDUs will almost always be involved in the EV market. Indeed, as the market grows and more electricity is consumed for use as a transportation fuel, their relevancy grows. The fact that EDUs will remain relevant in the EV market is also demonstrated by the significant roles EDUs play in transforming the EV market through education and outreach efforts with workplaces, fleets, and public charging station providers, a role that CARB has noted. EDU's efforts with respect to innovation and research, improved customer service, development of codes and standards, dissemination of best practices and lessons learned, EV rate incentives for business customers, and new metering solutions, benefit all of the market sectors that CARB has identified. (SCEC)

C-28. Comment: CalETC disagrees with CARB staff that "allocating LCFS credits to utilities in all market segments does not further the goal of “maintaining relevancy." EDUs are relevant as either the primary regulated party in the residential market segment or the alternate regulated party in the fleet, workplace, and public-access market segments. EDUs' relevancy is also demonstrated by their significant roles in transforming other markets, such as with the adoption of energy efficiency measures, and EDUs will do the same with the PEV market through education and outreach efforts with workplace, fleets, and public charging station providers, a role which CARB has acknowledged. The efforts from EDUs with respect to innovation, research and development, and new metering solutions, benefit all of the market sectors that CARB has identified.

In addition, EDUs, due to the transparency and oversight created through regulation, provide assurance that LCFS credit value will be returned to PEV customers in a fair and enforceable manner. The regulated environments in which EDUs operate provide an advantage to CARB in its implementation of the program. PEV owners, third-party EVSPs, and host charging sites are all EDU customers that will receive the benefit of LCFS credits through EDU programs. Accordingly, EDUs are relevant in all market segments and as regulated entities will help advance CARB staffs goals of maintaining relevancy. (CALETC1)

C-29. Comment: One thing we wanted to point out was in the staff report, the staff indicated that allocating LCFS credits to the utilities in all market segments might not meet the goal of maintaining relevancy. CalETC does believe that the utilities are incredibly relevant and that making them the primary recipient of the LCFS credit value in the residential market and the secondary and all the other market segments indicates that, and we very much support the recommendation of the staff.(CALETC2)

Response: Awarding utilities primary regulated party status in the case of residential charging and default regulated party status in the cases of fleet charging, workplace charging, and public charging clearly demonstrates our belief that utilities will continue to have strong connections in these markets in the future. However, we seek to encourage the growth of fleet charging, workplace charging, and public charging services. Providing the opportunity to earn credit through the LCFS to fleet operators, employers, and EVSPs will encourage the establishment of the charging services that are critical to the future EV market.

C-30. Comment: Credits should NOT be used by utilities to subsidize or otherwise promote their own charging equipment, installation or services.(ECOTALITY1)

Response: The amendments require all credit proceeds to directly benefit EV customers. For instance, utilities may use the proceeds to provide lower EV electricity rates. In addition, per CPUC decision, IOUs may not own charging equipment.

C-31. Comment: Utilities should be required to return the value of any LCFS credits to the customer through a cash rebate or other mechanism that allows the value to be re-invested in the cost of EV ownership. (ECOTALITY1)

Response: The proposed amendments require all regulated parties to use credit proceeds as direct benefits to EV customers. By design, this requirement is expected to lower the cost of EV ownership.

C-32. Comment: Plug In America believes that the EVSPs should in turn pass any LCFS credits, directly to consumers as rate reductions, rebates, or reductions in monthly fees for their services. (PIA)

Response: Section 95484(a)(6)(B)(1) requires all credit proceeds to be used as direct benefits for current EV customers. It is not prescriptive in how the credit proceeds will be passed on.

C-33. Comment: Any "public education" provided by utilities supported by LCFS proceeds should be clearly defined with performance metrics, such that the value to the consumer is clear and they return the maximal value to the customer. The education must be competitively neutral. CARB should set more explicit rules on public education that make it clear the education should focus on the overall benefits of EV adoption, not a specific utility's product or service offering. (ECOTALITY1)

Response: The amendments require EDUs to educate the public on the overall benefits of EV transportation to be eligible to receive credits. Further, no LCFS credit proceeds may be used for EV education. Staff will continue to monitor the need for additions and modifications to the electricity regulated party provisions and requirements. Changes may be considered in the future if necessary.

C-34. Comment: The creation of the fund controlled by the utilities does not achieve CARB's goal of "benefitting EV customers". Education and outreach activities are already funded by government agencies such as the California Energy Commission through AB 118 funding. In addition, funding has appropriately been directed towards cities and other stakeholder groups that support EV deployment to engage in education and outreach activity. The focus of EV customer benefit should be directed to further investments in the deployment of grid enabled EVSE that assists CARB to meet AB 32 standards. Moreover, the Phase 2 decision directed the utilities to "request approval for ongoing or future education costs education and outreach efforts within their general rate cases"

(p. 64 Phase 2 Decision). The approach proposed in this regulatory order is at odds with the direction of the Commission. (ECOTALITY1)

Response: The proposed amendments do not create a fund controlled by the utilities. Utilities are required to use *all* credit proceeds as benefits for EV customers. The amendments are not at odds with the direction of the Commission (see also response to Comment A-1).

C-35. Comment: CARB may wish to reconsider the use of credit value proceeds to fund education and outreach efforts by utilities. (SCEC)

Response: Staff will continue to monitor the need for additions and modifications to the electricity regulated party provisions and requirements. Changes may be considered in the future if necessary.

C-36. Comment: While requiring education and outreach as a precondition, the Proposed Amendments do not allow for the use of LCFS proceeds to fund such efforts because they require the use of *"all* credit proceeds as *direct* benefits for *current* EV customers" (emphasis added). While vital, education and outreach, by its nature, is not an exclusive direct benefit to current EV customers, NRDC supports the simplicity inherent in ARB's Proposed Amendments as it ensures that all credit proceeds will be used to improve the economics of vehicle electrification at this critical stage in the market's development. In the future, when the total value of LCFS proceeds in the electricity sector is more substantial, ARB may wish to re-direct some portion of proceeds towards additional activities that accelerate the electric vehicle market, informed by the knowledge and experience gained in the intervening years. For now, however, NRDC recommends that ARB keep it simple and ensure that all credit value is used to provide an additional incentive to drive on electricity. (NRDC2)

C-37. Comment: Although we understand why the CARB staff does not want to allow any LCFS credit value to be used for education and outreach, we would like to recognize that education and outreach is critical for the success of this new market and EDUs are actively involved in such efforts. We believe there could be benefits in using LCFS credit value for education and outreach efforts and will continue to work with CARB staff on how to best achieve these benefits in the future. (CALETC1)

Response: We acknowledge that there may be refinements to the requirements for electricity credit revenue that could better serve EV market growth in the future. We look forward to continuing to work with stakeholders to adjust requirements if necessary.

C-38. Comment: It is not clear on what grounds the EO will approve or disapprove of the utility becoming eligible to opt in. SCPPA appreciates that the EO needs to know which party will be claiming the credits. However, an approval requirement should not be included unless there is a clear statement of the circumstances in which approval will be withheld.

Rather than an approval provision, a notice provision should be included under which the EO notifies the electrical distribution utility if the EVSP does not become the regulated party or ceases to perform the relevant obligations. As the regulator, the ARB will have the most complete and accurate methods for identifying whether an EVSP has not elected to become a regulated party, or fails to meet or has ceased to meet the criteria for receiving credits. To assist with this procedure, the application or registration form to be completed by the EVSP should include a space for the name and contact details of the relevant electrical distribution utility. (SCPPA1, SCPPA2)

C-39. Comment: First, we urge removal of the requirement that there must be Executive Officer approval of electric utility opt-in as an alternate when an EVSP, a fleet operator, or business owner can't claim credits. We don't see what requiring that step of EO approval would accomplish. (SCPPA2)

C-40. Comment: Second, we urge that a provision be added for the Executive Officer to provide notice to the electric utility when it becomes eligible to opt in as an alternate to an EVSP, fleet operator, or business owner. It's hard to see how an electric utility would know when it can step in as an alternate without such notice. We proposed language for these revisions in our written comments, and we hope that the revisions can be included in the proposals that are circulated for 15-day comment. (SCPPA2)

C-41. Comment: However, SCPP proposes minor revisions to sections 95484(a)(6)(B), (C), (D) and (E) of the Proposed LCFS Regulation to include a requirement to notify an electrical distribution/utility, as second-priority credit recipient, that it has become eligible to opt in as the regulated party and to remove the requirement for the Executive Officer ("EO") to approve such opting in. (SCPPA1, SCPPA2)

C-42. Comment: Section 95484(a)(6)(D) on private workplace charging should provide for EO notice, not approval. For the reasons set forth above regarding section 95484(a)(6)(B), section 95484(a)(6)(D) of the Proposed LCFS Regulation on the responsible party in relation to credits for workplace charging should be amended. There should be a provision for the ARB to notify the utility if it becomes eligible to become the regulated party. (SCPPA1)

C-43. Comment: However, as discussed above, there should be no requirement for EO approval for utilities to opt in, in the absence of provisions on when approval will or will not be granted. (SCPPA1)

C-44. Comment: Section 95484(a)(6)(C) of the Proposed LCFS Regulation sets out the responsible party in relation to credits for charging fleets of EVs. This section should be amended to parallel the recommended amendments to section 95484(a)(6)(B), above. The EO should notify the utility if the fleet operator does not elect to become a regulated party or fails to meet the criteria for receiving credits. (SCPPA1)

Response: The amendments include provisions for default regulated parties in cases where the initially intended regulated party does not meet regulation obligations, goes out of business, does not have interest in being a regulated party, or otherwise cannot be located. In some of these instances, ARB staff will be aware of the opportunity for the default regulated party to apply for EO approval. However, ARB does not keep track of each charging station and whether potential regulated parties are reporting the electricity usage. In many instances the local utility will have more contact with fleet owners and local employers. Furthermore, local utilities will be more aware of public charging locations that may no longer be maintained or serviced by an EVSP. Therefore, each case of potential default regulated party will be examined closely by the EO to assure only one party is reporting for credits at a particular charging location. We will work with potential regulated parties to maximize the possibility that credits will be claimed, but not double-claimed.

C-45. Comment: It appears therefore that the Proposed LCFS Regulation was designed to allow for credits to be generated for alternative fuels supplied to off-road vehicles, with the sole exception of section 95484(a)(6)(E) which is specifically restricted to on-road vehicles. However, SCPPA understands that various practical issues with credit supply must be resolved before credits for fuelling off-road vehicles can in fact be generated. SCPPA supports further work on these issues in 2012. When issues relating to credits for off-road vehicles are resolved, the LCFS Regulation should be revised to remove the restriction to on-road vehicles in section 95484(a)(6)(E). (SCPPA1)

C-46. Comment: SCE respectfully requests that CARB add language directing staff to address the topic of nonroad EVs and electric rail and transit as part of its December 15 Board Resolution. In addition, the Board Resolution should direct CARB staff to investigate and clarify the primary and alternate regulated parties for other ET [electric transportation] technologies, and to amend Section 95484(a)(6) to add a new subsection designating the regulated party for electric transportation outside of light-duty on-road vehicles. (SCEC)

C-47. Comment: SEC has long supported the role of electric transportation beyond light-duty plug-in electric vehicles in the current regulation and understands that these electric transportation ("ET") technologies are included due to the definition of transportation fuel. Incremental GHG reductions from these technologies can increase by several million metric tons per year by 2020. Because of the substantial potential for credit generation from other ET technologies, it is crucial to allow them to do so as soon as possible. (SCEC)

C-48. Comment: CMUA understands the complexities of including off-road sources under the current proposed set of amendments, and recommends that ARB staff examine the possibility of including off-road sources, such as electrified mass-transit (lightrail), in future LCFS amendments. (CMUA1)

C-49. Comment: ARB should develop regulations to support electrification beyond light-duty vehicles. (NRDC1)

C-50. Comment: The restriction to on-road vehicles in section 95484(a)(6)(E) should also be revisited when issues relating to credits for off-road vehicles are resolved in 2012. These changes will help to maximize the number of credits that are claimed and available for use by regulated parties and reduce the number of unclaimed credits. (SCPPA1)

C-51. Comment: During the September 14 workshop, ARB staff confirmed that all forms of transportation, except those explicitly excluded in §95480.1 (d), are eligible to earn credits in the LCFS program. However, for certain types of eligible transportation, such as light rail and other electrified mass-transit systems, the factors necessary for compliance calculations, such as Energy Economy Ratios (EER), are not included in the LCFS regulations. Until these factors are included, most forms of electrified mass transit are unable to participate in the LCFS program. The SFPUC recognizes that technical details for the inclusion of light rail and other forms of electrified mass transit need to be worked out, but recommends that the regulations be modified as soon as possible. Broad eligibility for mass-transit options that use electricity as an alternative to petroleum-based fuels encourages both (i) increased fuel switching from high carbon petroleum to low-carbon electricity, and (ii) increased use of mass transit in favor of less efficient modes in terms of vehicle miles and hours travelled. The SFPUC recommends that the ARB recognize mass transit as a distinct category within the transportation sector and prioritize establishment of the factors necessary to allow electrified mass transit to fully participate in the LCFS program. To ensure that enabling regulations are developed without delay, CCSF recommends that the ARB issue a resolution directing the Executive Director and staff to prioritize establishment of LCFS credits for all forms of electrified mass transit, with completion by December 2012. The SFPUC stands ready to work with the ARB to develop the appropriate factors. (SFPUC)

C-52. Comment: Lastly, we urge that the restriction to on-road vehicles be revisited when issues relating to credits for off-road vehicles are resolved in 2012. (SCPPA)

C-53. Comment: I did have one comment today regarding the complexities of adding off-road such as mass transit, but I do see it in the Resolution that this is going to be looked at in the future in 2012. (CMUA2)

C-54. Comment: The ARB should issue a resolution directing the Executive Director and staff to prioritize establishment of LCFS credits for all forms of electrified mass transit, with completion by December 2012. (SFPUC)

Response: In Resolution 11-39, the Board directed the Executive Officer to work with interested stakeholders to investigate the feasibility of developing into regulatory language for future rulemaking(s) the concept of issuing credits for nonroad electricity-based transportation sources, including mass transit. We intend to investigate the feasibility of this proposal in the near future.

C-55. Comment: SCE supports the change in direction in the Proposed Regulation Order of awarding credits by market segment rather than the current regulation's method of using definitions based on business models. Business models are frequently changing and multiple business models can apply to the same customer. In addition, as proposed in SCE's earlier comments, additional refinements should be made in an LCFS Guidance Document over the next year to more clearly define the four market segments. (SCEC)

C-56. Comment: SCE recommends that the LCFS Guidance Document be updated or additional regulatory advisories be issued in 2012 to work through any implementation issues for the regulated parties for electricity as a transportation fuel. For example, in prior comments, SCE has asked CARB to clarify issues surrounding the content of annual reports, verification by CARB of regulated parties, allowing an EDU to become an alternate regulated party, minimizing multiple claims on the same LCFS credit, as well as requirements on the measurement of kWh in the LCFS program. (SCEC)

C-57. Comment: CMUA suggests that ARB develop guidance documents to assist stakeholders with any implementation issues. (CMUA1)

C-58. Comment: Still, additional refinements could be made in an LCFS Guidance Document over the next year to more clearly define the LCFS electricity market segments. SCE looks forward to working closely with CARB staff to further simplify and clarify the regulation. (SCEC)

Response: We will update the LCFS Guidance Document to address electricity issues as appropriate.

C-59. Comment: We do recognize that there’s more work ahead. And as ARB begins the implementation process, we do encourage staff to consider developing additional guidance documents to assist stakeholders with any implementation issue. (CMUA2)

Response: We will consider developing guidance documents if issues arise that would appropriately be addressed in this way. It is possible that guidance documents for the application of electric off-road vehicles and mass transit may be necessary.

C-60. Comment: Requiring each regulated party for electricity (whether a utility, EVSP or other entity) to show a pathway of electrons from a particular generating station to the regulated party would be an exercise in futility. It is not possible to trace system electricity that is supplied to EV charging stations back to any particular electricity generating station, given that electricity from all sources is indistinguishable once it is in the transmission or distribution system. Furthermore, there appears to be no need for the LCFS Regulation to require demonstration of a physical pathway for electricity given that all electricity, regardless of its source, is an eligible fuel under the LCFS Regulation if it is used for transportation. Separate requirements apply to the demonstration that a particular amount of electricity has been used as transportation fuel (see section 95484(b)(3)(C)); this is the only information that should be required. (SCPPA1)

C-61. Comment: The Proposed LCFS Regulation should be revised to remove the requirement for regulated parties to show a physical pathway for electricity, to avoid having a regulatory requirement that cannot be complied with, is not necessary, and is not being enforced. (SCPPA1)

Response: For electricity, the regulation's physical pathway requirement is satisfied as long as the EV charging takes place in California. The physical pathway by which the electricity was supplied to the charging equipment (and vehicle) is designated by the Electrical Distribution Utility in the service area in which the charging equipment is located. We accept the stationary distribution system as the physical pathway for the electricity fuel.

C-62. Comment: The term "on-road" is not defined in the Proposed LCFS Regulation or in the Health and Safety Code definitions incorporated into the Proposed LCFS Regulation by reference. This term is not used elsewhere in the Proposed LCFS Regulation, although the term "off-road" is used in Table 5 in section 95485(a), listing energy economy ratios for various fuels and applications. The definitions of "transportation fuel" and "motor vehicle" are broad enough to cover off-road vehicles (such as forklifts, tractors, mining vehicles, and other industrial vehicles), and the list of exempted vehicles in section 95480.1(d) of the Proposed LCFS Regulation does not exempt off-road vehicles. (SCPPA1)

Response: We defined the term "on-road" in amendments made in the first 15-Day Change Notice. The Regulation does not specifically exclude off-road vehicles. In Resolution 11-39, the Board directs the Executive Officer to work with interested stakeholders to investigate the feasibility of developing into regulatory language for future rulemaking(s) the concept of issuing credits for nonroad electricity-based transportation sources, including mass transit.

C-63. Comment: SCE suggests that CARB define the term "EV" broadly to mean light-duty plug-in vehicles, including BEVs and PHEVs. (SCEC)

Response: A definition for "EV" was added in the first 15-Day Change Notice.

C-64. Comment: This section refers to a "company" that operates a fleet. This is restrictive, as it would not appear to allow entities other than companies to be considered fleet operators. Instead, any "person" should be able to be a fleet operator. This would be consistent with the usage of "person" in other provisions of the Proposed LCFS Regulation—for example, section 95480.2, *Persons Eligible for Opting into the LCFS Program.* (SCPPA1)

Response: We agree and have revised the provision as suggested in the first 15-Day Change Notice.

C-65. Comment: Section 95480.3(b) of the Proposed LCFS Regulation states that:
As part of its registration, the regulated party of a fuel listed in subsection 95480.1 (b)(l)(A)-(F) must elect for each of its opt-in fuels a carbon intensity (Cl) value using one of the following methods: ...
However, section 95480.1 (b)(1) has no subsections (A) through (F)—it has no subsections at all. The correct reference may be to section 95480.1(b), subsections (1) through (6), containing a list of "opt-in" fuels. This cross-reference should be corrected. (SCPPA1)

Response: This error has been corrected in subsequent first and third 15-Day Change Notices.

C-66. Comment: SCE requests that CARB revise the regulation so as to not preclude the current and ongoing estimation of kWh when an EDU opts to become the default regulated party. Specifically, CARB should delete the word "measured" in Section § 95484(a)(6)(E). (SCEC)

Response: Section 95484(a)(6)(E) provides for the Electrical Distribution Company to opt-in as the regulated party with EO approval for non-residential charging not covered in sections 95484(a)(6) (B) through (D). Because the electricity covered in this section is non-residential, it must be metered to be eligible for credits. Non-residential charging is not eligible for the estimation methods covered under section 95484(b)(3)(C)(1)(b) .

C-67. Comment: The restriction to on-road vehicles in section 95484(a)(6)(E) should also be revisited when issues relating to credits for off-road vehicles are resolved in 2012. These changes will help to maximize the number of credits that are claimed and available for use by regulated parties and reduce the number of unclaimed credits. This is a priority of the ARB, as set out in the *Initial Statement of Reasons for Proposed Rulemaking* for the Proposed LCFS Regulation. (SCPPA1, SCPPA2)

Response: ARB staff continues to evaluate the feasibility of applying the electricity regulated party provisions to off-road vehicles and the impacts doing so may have on both the LCFS compliance schedule and credit market. If we determine that it is appropriate and necessary to make such a change after this evaluation is completed, amendments addressing this change would be proposed in a future rulemaking.

D. Program Structure

Implementation

D-1. Comment: The California Independent Oil Marketers Association (CIOMA) *respectfully requests that you immediately suspend the Low Carbon Fuel Standard (LCFS).* This regulatory package may have the most significant impact on California fuel costs that ANY previous legislative/regulatory endeavor has ever had. CIOMA represents independent marketers who purchase gasoline and other petroleum products from refiners and sell the products to - independent gasoline retailers, businesses, and government agencies, as well as representing branded "jobbers" who supply branded retail outlets, especially in rural areas. Our members are primarily small, family owned businesses who encounter unique difficulties in meeting California's complex and increasingly expensive environmental requirements. We represent approximately 400 members, about half of whom are actively engaged in the marketing and distribution of petroleum products and fuels. We will be directly and materially affected by this regulation.

Among our reasons for immediate suspension: There are MANY, MANY unanswered questions regarding how this program will be implemented. (CIOMA)

Response: This commenter appears to be suggesting a suspension of the entire LCFS regulation based, at least in part, on an unspecified number of unidentified implementation questions CIOMA and its members have. First, the entire regulation was not proposed for amendment in the 45-day notice of proposed rulemaking. Rather, the vast majority of the substantive aspects of the regulation were left alone, with the Board-approved amendments primarily targeting technical changes and other improvements in the regulation. Because the 45-day notice called for public review and comments on technical amendments and refinements, rather than the regulation as a whole, this comment falls outside the scope of the notice and requires no further response.

With that said, we appreciate that certain stakeholders, particularly smaller companies, may have some difficulty understanding the regulation and its requirements. To this end, ARB solicited input specifically from CIOMA when work began on the LCFS Guidance Document. In fact, version 1.0 of that Guidance Document (June 2011) reflects the input received from CIOMA. Indeed, the Guidance Document dedicates the first eight pages of its 29 pages to providing plain English explanations of the regulation. [See http://www.arb.ca.gov/fuels/lcfs/LCFS_Guidance_%28Final_v.1.0%29.pdf.]

ARB remains committed to providing as much assistance to stakeholders as possible and is available for consultation with CIOMA members and other stakeholders as needed.

D-2. **Comment:** We support CARB's proposal to maintain strong fuel accounting provisions to ensure that petroleum fuels do not become dirtier over time, thereby undermining the LCFS and our clean air goals. A strong LCFS should support, not hinder, California's clean air and climate goals. We believe that the program should maintain the on-time implementation of the LCFS program to ensure that our transportation fuels meet and exceed the goals of a ten percent reduction by 2020. (ALA)

Response: We agree. The overall carbon intensity reduction requirement of 10 percent by 2020, relative to a baseline that was recalculated to reflect more accurate information than was available in 2009, has not been changed with the amendments approved by the Board.

Compliance

D-3. **Comment:** Given that we aren't even sure that there will be sufficient blending stocks to comply with this measure, why are we moving forward? Would it hurt to do more research on how this regulation could actually be successful before pushing an extremely costly burden on an economically crippled region? Fuel prices account for a larger portion of our budgets than they ever have, yet we are thinking of ways to increase them further during the largest recession we've seen in our generation. We all want clean air and we all want to find ways to become more independent in our fuel supply. Please reconsider more attainable and achievable goals for this regulation. (OSD)

Response: The amendments approved by the Board made technical refinements and other improvements to the LCFS regulation without changing the vast majority of the substantive aspects of the regulation. [ISOR at ES-1.] This includes leaving alone both the overall carbon intensity reduction requirement (10 percent reduction by 2020 relative to a recalculated baseline) and the technical and commercial feasibility analyses conducted in support of the compliance schedule adopted in the original 2009 rulemaking. [Sections 95482, 95486(b)(1), and ISOR at 37-39; ARB 2009 ISOR at III-1 through III-21 and VI-1 through VI-22.]

By contrast, the commenter raises a concern about the ability of stakeholders to meet the regulation’s carbon intensity reduction requirement. As noted above, neither the overall compliance schedule nor its supporting technical and commercial feasibility analyses were the subject of the amendments. Because of this, the commenter raises a question that falls outside the scope of the 45-day notice of proposed rulemaking, and no further response is required.

D-4. Comment: Under the best of circumstances, the LCFS would not result in sufficient greenhouse, gas emissions reductions to reduce global warming. Ironically, the related escalation in imports is likely to increase net GHGs from their production and transport. With California's economy stagnating in the worst recession since the Great Depression, the imposition of billions in higher fuel costs and constraint of fuel supplies without a measurable reduction in global warming cannot be justified. (COALITION)

Response: We disagree. In approving the original LCFS regulation in 2009, the Board found that the regulation is expected to significantly reduce GHG emissions by about 16 million metric tons of CO_2 equivalents. [Resolution 09-31 at 9.] In approving these amendments, the Board reaffirmed the estimated 16 MMT $C0_2$e reductions as remaining valid for the amendments. [See ISOR at ES-6, and Resolution 11-39 at 2.]

As noted above, most aspects of the regulation, including the compliance schedule, overall carbon intensity reductions, and supporting commercial and technical feasibility analyses, were not subject to comment under the 45-day notice of proposed rulemaking for these amendments. Therefore, this comment falls outside the scope of the notice, and no further response is required.

D-5. Comment: Shell continues to have concerns regarding the achievability of the LCFS. Our analysis is consistent with the analysis that the Western States Petroleum Association presented to the Advisory Panel, which indicates that the LCFS likely becomes infeasible before 2015. Shell continues to believe that it is critical that the ARB establish reasonably achievable standards. This is critical to ensure that the LCFS does not have unintended serious adverse consequences for consumers and the economy of the State, as well as creating the right environment that will encourage significant investments in alternative fuels.

The Board should consider that there continue to be significant challenges in the commercialization of tomorrow's advanced biofuels such as those using cellulosic feedstocks and "drop-in" biofuels which are fully fungible with gasoline and diesel. Many biofuel feedstocks and process technologies that are promising at bench scale are just beginning to be developed through the scale-up process. If successful they may reach commercialization within the next ten years.

Regulators should work with industry to create stable, long-term policy frameworks for biofuels to increase investor confidence and allow for the sustainable expansion of biofuel production. A critical aspect of this is that biofuel targets must be economically and technically achievable by obligated parties, with incentives aligned with compliance requirements and goals that include realistic timescales for implementation. If they are not viewed as such, investor confidence will be low. (SHELL)

Response: The overall compliance schedule, carbon-intensity reduction requirements, and the supporting commercial and technical feasibility analyses from the original 2009 rulemaking were not subject to the 45-day notice of proposed rulemaking. Therefore, this comment falls outside the scope of the notice, and no further response is required. With that said, the ARB continues to monitor the implementation of the LCFS, and is required to conduct another formal program review, the results of which are due to be presented to the Board by January 1, 2015. We will, of course, work with stakeholders in conducting the 2015 review as well to continue identifying ways in which the regulation may be enhanced moving forward.

D-6. Comment: The AEC supports adjusting the compliance schedule to account for changes to the CaRFG baseline from 2006 to 2010, but opposes ethanol's inclusion in the baseline. As discussed in earlier sections, the carbon intensity of producing and transporting crude oil in California has increased by roughly 20 percent over the last four years. We support efforts to adjust the compliance schedule to reflect the most recent data. However, it remains unclear to the AEC why ethanol is included in the baseline. This creates unnecessary uncertainty with regard to how the baseline will evolve as the ethanol industry evolves, and seems inconsistent with the underlying premise of the LCFS to encourage different fuels to compete with one another based on performance. It also has the potential to dilute the true market value of lower carbon ethanol fuels by masking the real differential between ethanol and gasoline vis-à-vis the roughly 1 billion gallons of ethanol currently averaged as part of the baseline. While advanced ethanol offers the lowest CI values of any alternative fuel eligible under the LCFS to date, the molecule ultimately blended with gasoline is identical to conventional ethanol. We believe it would be better and more consistent to remove ethanol from the baseline and allow it to compete in the marketplace as an alternative fuel against a CARBOB baseline. (AEC)

Response: Ethanol was included in the gasoline baseline as part of the original 2009 LCFS rulemaking in order to reflect actual California reformulated gasoline, and these amendments did not change that. The Board's rationale for including ethanol in the baseline was explained thoroughly in the 2009 rulemaking record. [ARB 2009 FSOR at 340, 442, 572.] Because no change was made to the fact that ethanol is included in the gasoline baseline, this comment falls outside the scope of the 45-day notice of proposed rulemaking. Therefore, no further response is required.

D-7. Comment: As discussed, AEC members are either breaking ground on first commercial advanced and cellulosic ethanol plants or are in the final stages of securing project finance. However, one of the challenges we face as an industry is the lack of an open marketplace in which ethanol is allowed to compete with petroleum based on price. Ethanol market constraints deprive the marketplace of a domestic fuel that could help stem the costs of foreign oil dependence, but they also have the potential to dampen investor interest in second generation ethanol production as the United States approaches what is often called the ethanol "blend wall." Overlying the blend wall problem is the federal Renewable

Fuel Standard (RFS) which calls on advanced biofuel producers to bring large volumes of fuel to market over the next ten years. While the bulk of the remaining fuel volume required by the RFS between now and 2022 is advanced biofuel, the federal government must more aggressively open the marketplace in order for our industry to reach its full potential. (AEC)

Response: The ARB has no authority to require the federal government to address the "blend wall," and no such change in the regulation was made by the Board in this regulatory action. Because of this, the comment falls outside the scope of the 45-day notice of proposed rulemaking. Therefore, no further response is required.

D-8. **Comment:** California is in the unique position to address some of these market constraints by virtue of its legal authority under the Clean Air Act (CAA). We are also aware that increased penetration of flex-fuel vehicles (FFVs) is a major factor in CARB's compliance scenario analyses going forward, and higher ethanol blends also appear in some of these scenarios. If California is to realize some of these scenarios and put the LCFS in a position to succeed in the short to medium timeframe, there are a number of strategies available to CARB to facilitate these outcomes. (AEC)

Response: As the commenter notes, flex-fuel vehicles play a role in the illustrative scenarios developed in support of the LCFS. This was recently demonstrated in the illustrative scenarios developed for the 2012 formal program review, conducted pursuant to section 95489 of the LCFS regulation. [See "Low Carbon Fuel Standard 2011 Program Review Report (Final)," December 8, 2011, http://www.arb.ca.gov/fuels/lcfs/workgroups/advisorypanel/20111208_LCFS%20program%20review%20report_final.pdf at 170-178.] However, neither the illustrative scenarios used in support of the original 2009 rulemaking nor the scenarios used in the 2011 Program Review Report were amended in this regulatory action. As such, the comment falls outside the scope of the 45-day notice of proposed rulemaking. Therefore, no further response is required.

D-9. **Comment:** For example, as you know, U.S. EPA has approved E15 for use in 2001 and newer vehicles. Higher ethanol blends offer a number of public health benefits, including lower toxic and soot emissions. However, in the context of the LCFS, providing flexibility for more (discretionary) ethanol blending will provide greater headspace for the development and deployment of advanced ethanol fuels. We understand the resources necessary to amend the CaRFG program. However, we encourage the Board to take into consideration the fact that CaRFG updates are required on a regular basis by California and advanced ethanol fuels have the upside of offering the lowest CI values of any fuel or electron eligible for use under the LCFS. (AEC)

Response: Currently, only E10 and E85 are approved for sale in California. For an ethanol blend level between these two levels to be legal for widespread sale in California, a fuel specification applicable to that blend level would need to be developed and adopted through a formal rulemaking. Such a rulemaking, if one were to be pursued by ARB, would occur separate from and independent of the LCFS regulation. Because no such ethanol blend level was adopted in this regulatory action, this comment falls outside the scope of the 45-day notice and requires no further response.

D-10. Comment: We also encourage the Board to consider the importance of vehicles to compliance with the LCFS. We believe California has unique authorities with regard to vehicle regulation, and there are a number of vehicle-based strategies that could be of tremendous value to a wide variety of low carbon alternative fuels. We would look forward to discussing a number of options related to opening the marketplace to advanced ethanol. (AEC)

Response: As noted in the original 2009 LCFS rulemaking, the LCFS is a part of ARB's holistic and comprehensive approach to addressing the three major components contributing to transportation GHG emissions: vehicle or engine efficiency, vehicle use, and the carbon intensity of the fuels. [ARB 2009 ISOR at ES-36.] Thus, we agree that vehicles play an important role in the control of GHG emissions, and ARB already has aggressive programs in place or under development to address vehicular efficiencies, use and emissions. With that said, the LCFS is a separate but complementary fuel-based regulatory program to those vehicular programs. Other than providing the cleaner fuels for advanced and alternative-fueled vehicles, vehicle-based strategies are best addressed directly in ARB's vehicular programs. Because ARB's vehicular programs were not amendment in this rulemaking, this comment falls outside the scope of the 45-day notice and, therefore, requires no further response.

<u>Flexible Compliance Mechanism</u>

D-11. Comment: The LCFS should include a flexible compliance mechanism that directly incentivizes investment into low-carbon fuels and creates compliance credits. Such a mechanism would provide certainty on how ARB would respond to market shortfalls, and would concurrently provide greater confidence for investors and would expand the availability of low-carbon fuels in later years. It would also provide flexibility should a regulated party be unable to meet an annual compliance obligation. (AEC, BIO, E2CF, SHELL)

Response: Currently, the information and analyses needed to design and adopt such a mechanism are not available, and the commenters did not provide specific details or recommendations that could be implemented as part of this rulemaking. Development and consideration of the advisability of a flexible compliance mechanism merits further investigation and may become the subject of a future rulemaking.

D-12. Comment: The ARB should include a compliance "off-ramp" mechanism that would automatically revise the compliance targets in the LCFS if specific early year benchmarks are not met. Such a mechanism should ensure that there is sufficient lead time to prevent disruptions in the transportation fuels market.

Additionally all program infeasibilities that may occur need to be included in the LCFS Periodic Review report. (WSPA1)

Response: ARB is already obligated to conduct periodic reviews of the feasibility of meeting the LCFS compliance targets. To date, these reviews have indicated that there are adequate supplies of lower-carbon fuels so that near-term compliance is expected. Staff has identified no compelling need to design and incorporate the requested mechanism into the LCFS at this time, and the commenter has proffered no such compelling need. Future program reviews will address the adequacy of low-carbon fuel supplies, and, if warranted, will provide an adequate opportunity to consider any needed changes to the LCFS compliance schedules.

D-13. **Comment:** The ARB should not include a compliance off-ramp mechanism that would automatically revise the compliance targets under specified circumstances. We are opposing any calls for delays or built in off-ramps to the LCFS program. (ALA2)

Response: We agree with this comment.

D-14. **Comment:** The use of unique identification numbers should be avoided, but sufficient identification should be provided to identify the producer of the credit and the date (or at least the year) the credits were produced. (WEAVER)

Response: The approved regulatory amendments specify that if the Executive Officer has provided a credit identification number to a credit holder, the credit holder must provide this number as part of a credit transfer and may specify a retirement hierarchy for credits. The Executive Officer has not yet determined if such an identification system should be established, and the detailed design and operation of such a credit identification system was not addressed in this rulemaking. If the Executive Officer establishes a system for identifying individual credits, the issues raised by these comments will be considered in that effort.

D-15. **Comment:** The credit market should be expanded by establishing an electronic trading platform that provides real time trades and cash flows, and the market should be expanded to allow companies that are not regulated parties to participate in the market for LCFS credits. (E2 and NRDC1)

Response: The approved amendments establish minimum requirements that must be met for credits to be transferred, but they do not establish the design of a credit trading market or trading platform. The detailed design and operation of a credit market was not addressed in this rulemaking. The regulation enables willing participants to transfer credits and allows for transfers to be facilitated by third parties. We believe that this is sufficient for LCFS credits to be traded over the near term. Meanwhile, we are working with a contractor to include in the LRT a credit balance and tracking module that will make credit trading more streamlined and accountable.

D-16. Comment: Would like to see the California Air Resources Board mandate major oil companies invest in renewable energy laboratories and if that is not feasible impose an abatement program for all emissions they release in the state. (SCOTT)

Response: Mandating oil companies to invest in specific fuel sectors is problematic, at best. ARB’s preferred approach is to maintain the LCFS’ fuel-neutral, performance standards and incentives structure. By design, the LCFS will reduce GHG emissions from fuels used in California. To the extent stationary facilities are built in the State to produce fuels to comply with the LCFS, the emissions from such facilities are subject to existing CEQA, local air district, and various additional local, State, and federal mitigation and other requirements.

D-17. Comment: Given that we aren't even sure that there will be sufficient blending stocks to comply with this measure, why are we moving forward? Would it hurt to do more research on how this regulation could actually be successful before pushing an extremely costly burden on an economically crippled region? Fuel prices account for a larger portion of our budgets than they ever have, yet we are thinking of ways to increase them further during the largest recession we've seen in our generation. We all want clean air and we all want to find ways to become more independent in our fuel supply. Please reconsider more attainable and achievable goals for this regulation.

Why is ARB pursuing a policy that their illustrative compliance scenarios barely convey is a feasible solution? Would it not be wise to take a more patient approach and further evaluate the economic costs that could be incurred if this regulation was not pursued in a haphazard fashion? (OSD)

Response: The regulation’s overall goal and design (i.e., to incentivize the reduction of transportation fuel carbon intensity for fuels used in California) was not the subject of this rulemaking. Therefore, this comment falls outside the scope of the 45-day notice and therefore requires no further response. It should be noted that the Board determined the approved amendments have no significant adverse impacts on the LCFS costs. The illustrative compliance scenarios noted by the commenter were discussed as part of the extra-rulemaking 2012 LCFS Program Review, which falls outside the scope of the 45-day notice and therefore requires no further response.

D-18. Comment: Finally, while we appreciate California's leadership in developing a workable plan to encourage the introduction of low carbon fuels, we believe a single, integrated, national program provides the most cost-effective approach to reducing the carbon content of transportation fuels. A federal approach to low carbon fuels also will help assure broad availability, market fungibility, maximum supply and lowest cost, both regionally and nationally. (AAM)

Response: This comment falls outside the scope of the 45-day notice and therefore requires no further response.

D-19. Comment: CalETC recommends 15-day changes to the proposed amendments to allow for third-party brokers who would ensure anonymity between buyers and sellers of LCFS credits. Without such anonymity, competition between parties could interfere with credit transactions. The LCFS credit market needs to be fuel neutral and based entirely on emissions reduced. The use of third-party brokers, whose role is to provide anonymity, would maximize the number of viable LCFS credits in the market. Such anonymity creates a healthy market for LCFS credits unimpeded by any external competition. (CALETC1, CALETC2, SCEC, NRDC1)

Response: We agree with this comment and modified section 95488(c)(3) in the first 15-Day Change Notice to allow credit transactions to go through blind trading while still providing ARB with information needed for the State to identify the credit seller and buyer.

D-20. Comment: Update the guidance document to accurately reflect the changes to the regulations and frequently asked questions that have been posed over the last year since the first version was released. (SCEC)

Response: We agree with this comment and plan to release a second version of the of the guidance document to reflect changes adopted in this rulemaking.

D-21. Comment: Going totally to "clean" fuels is now and will be too expensive to be economically sound policy. I do not support forcing any company to spend for additional cleaner burning fuel. I do not support adding to California's current carbon fuel standards. They are difficult enough to adhere to already. (PETTIGREW)

Response: We disagree. In the original 2009 rulemaking, the Board found that the LCFS did not have a significant adverse impact on California consumers and businesses. Similarly, in this rulemaking, the Board found that the modifications to the regulation approved in its December 2011 hearing also had no significant adverse impacts on California consumers and businesses.

D-22. Comment: WSPA has a serious concern about feasibility of LCFS program in two to three years' time combined with concern over potential impacts and costs to not only our industry but to the state and consumers overall. (WSPA1, WSPA3)

Response: Because the feasibility of the LCFS compliance standards was not subject to public comment in this rulemaking, this comment falls outside the scope of the 45-day notice. Therefore, no further response is needed.

D-23. Comment: Indications are that adequate and reliable volumes of low carbon intensity fuels and credits will not be available as was originally anticipated by ARB in 2009. EIA, EPA and CEC have all indicated the anticipated growth in cellulosic low CI biofuels, for example, has not materialized for either the RFS2 program nor for the projected needs of the LCFS program. This will be exacerbated if other states adopt a LCFS program. Although some credits have been banked in the first year of the program, they are not significant enough, and it is not realistic to expect this bank to continue to grow due to large deficits to be incurred. (WSPA1, WSPA3)

Response: Because the feasibility of the LCFS compliance standards was not subject to public comment in this rulemaking, this comment falls outside the scope of the 45-day notice. Therefore, no further response is needed.

D-24. Comment: WSPA requests the Board ask staff to analyze a "trigger" mechanism insertion in the regulation (NOT an alternative compliance mechanism) that would get triggered if certain criteria are reached in the program. This needs to be a priority topic at the beginning of 2012. (WSPA1, WSPA2)

Response: Because the feasibility of the LCFS compliance standards was not subject to public comment in this rulemaking, this comment falls outside the scope of the 45-day notice. Therefore, no further response is needed.

D-25. Comment: WSPA requests that the Board ask staff to initiate a thorough analysis of alternatives to transportation sector GHG emissions reductions. Based on experience and knowledge gathered to date, we believe there may be less costly alternative approaches than a LCFS program. If the state wants to promote select technologies and fuels it can be done in ways that are not structured like the LCFS. (WSPA1, FC)

Response: Because the LCFS compliance standards and alternative approaches to achieving the LCFS objectives were not subject to public comment in this rulemaking, this comment falls outside the scope of the 45-day notice. Therefore, no further response is needed.

D-26. Comment: How will the LCFS implementing regulations acknowledge other carbon management systems? In particular, will credits be allocated under the LCFS for other carbon management policies, such as carbon pricing? We note that the Province of Alberta has three carbon compliance options for industry: a 12 percent physical emissions reductions; the purchase of an accredited Alberta offset; or, a payment of $15 per tonne to a fund that supports the development and application of transformative technologies. (NRC)

Response: The revisions to the regulation do not change the interchangeability of credits generated under the current regulation in relation to other AB32 programs. LCFS credits will remain exportable to other GHG reduction initiatives, subject to whatever import requirements those initiatives may impose on such credits. However, the approved modifications to the regulations contained no provisions allowing the import of credits from other programs into the LCFS program.

D-27. Comment: Lack of information to fuel marketers regarding blending below the rack - We have asked CARB staff on several occasions to provide a simple discussion on what our members, who might have an interest in blending low carbon components below the rack, will experience under LCFS. This information is critical to making an educated business decisions' about the opportunities and risks of such a decision. We have not received this critical information and our members are "flying blind" on what risks and opportunities may be inherent in this program. CARB is legally obligated to assist small businesses (our members) in complying with and operating in your regulatory environment. (CIOMA, CMUA2)

Response: Contrary to the commenter's assertion, ARB has already issued a guidance document and made it available to the general public. See http://www.arb.ca.gov/fuels/lcfs/LCFS_Guidance_%28Final_v.1.0%29.pdf. The document provides guidance in a frequently-asked-questions (FAQ) format to a number of key questions raised by stakeholders since the original 2009 rulemaking, including those raised by this commenter. The guidance document specifically addresses the concern for below-the-rack blenders and the documents needed to be retained and reported if further blending with obligated fuel occurs.

D-28. Comment: We have been made aware that at least two common-carrier racks in this state will shortly begin supplying nothing but BD-5 biodiesel blends for diesel fuel. Under current requirements this fuel can be sold simply as "diesel fuel". Our members will not know how much biodiesel will be included in each load. For those that provide below-the-rack blending, this will create serious problems in how to label and market the further-blended biodiesel, with potential for excessive liability, mislabeling, and engine compatibility issues. LCFS creates this problem but does not address this issue. (CIOMA)

Response: The labeling of transportation fuels was not among the modifications approved in this rulemaking. Because of this, this comment falls outside the scope of the 45-day notice. Therefore, no further response is needed. It should be noted that biodiesel labeling is among the various factors being considered as part of the upcoming ARB rulemaking to establish fuel specifications for biodiesel, renewable diesel, and other alternative diesel fuels (tentatively scheduled for a 2013 hearing).

D-29. Comment: We understand at these facilities, the low carbon additives will be comingled in common storage. Therefore, while the purchaser will receive a transfer document that contains carbon-intensity information from the fuel supplier, the actual fuel is likely to NOT be of the carbon intensity described. This may lead to false advertising and possibly product quality liability issues. LCFS creates this problem but does not address this issue. (CIOMA)

Response: This comment falls outside the scope of the 45-day notice and therefore requires no further response. It should be noted that the aforementioned LCFS Guidance Document provides guidance on accounting and recordkeeping with regard to commingled fuels.

D-30. Comment: As we have discussed in numerous pieces of correspondence before, there is a complex, ad hoc system for determining whether fuels are fully vetted and are legally dispensable in this state and the nation. LCFS has made no attempt to unravel this nest of complexities. CARB merely certifies the carbon intensity of the fuel, not its passage of key check points on whether the fuel has met various certifications and checkpoints to be a legally dispensable fuel. Marketers and transporters are left holding the bag on potential liability and/or compliance status without any centralized assessment system. (CIOMA)

Response: This comments falls outside the scope of the 45-day notice and therefore requires no further response. ARB is available for consultations with stakeholders to help them better understand the LCFS and other ARB fuels regulations.

D-31. Comment: An expansion to the credit trading market should take two forms: 1) An electronic trading platform for LCFS credits providing electronic, real time credit trades and cash flows to our businesses. 2) An expansion of the companies that can participate in the market. The transparency and volume of trades will create clear credit prices, providing a way for us to understand the market value of carbon reductions. Such a credit trading system would facilitate our capacity to provide increasing quantities of low carbon fuels into California, and help achieve the LCFS targets. (E2CF, AEC, BIODICO, NRDC5)

Response: We agree. ARB is currently procuring the means to design and build a platform that can be incorporated into the LCFS Reporting Tool (LRT) and allow regulated parties the ability to manage their credits like a bank account. Regarding the commenter's second comment, the amendments expanded the universe of potential regulated parties by providing for the opting in of entities both upstream of the importer and downstream of the producer, depending on the circumstances. See amendments to section 95480.2. However, we remain apprehensive about opening the market to non-regulated parties at this stage of the program because non-regulated parties will likely add to market speculation, which could adversely affect credit prices beyond affordability. However, staff's investigation of this matter continues.

D-32. Comment: Stop this madness. (Commenter provided a document with the words "Stop this madness" as well as an attached article). (HNEWTON)

Response: The comment "Stop this madness" does not indicate which part of the proposed amendments it refers to. We acknowledge commenter's statement, but are unable to provide a specific response as relates to the current amendments. The article commenter attached relates to ethanol shuffling between Brazil and the United States. We did not propose amendments in the 45-Day Notice for this rulemaking to change treatment of ethanol from Brazil. Therefore, the article attached to the comment is outside the scope of the 45-day notice and therefore requires no further response.

D-33. Comment: The nascent compliance market is not yet sending a meaningful signal to investors. Create a price transparent credit trading system that presents market information in a way that protects specific transactions, but is transparent about market level trends in real time. Quarterly information is not sufficient. (BIO)

Response: We agree. Staff is currently working to develop a transparent credit trading platform, which will be implemented when such work has been completed.

D-34. Comment: We propose some type of "statute of limitations" on the time CARB has to "review and adjust" credits. Without this type of provision, CARB could conceivably adjust or revoke credits outside a timeframe that exceeds reasonable business expectations and commercial requirements for finality. This problem would be compounded if past credits were carried forward, used to demonstrate compliance, and then later found to be invalid or fraudulent. We recommend a 1-year time limit in which credits can be revoked or otherwise adjusted by CARB because of deficiencies in credit generation and/or transfer. (CONOCO1)

Response: We understand the concerns raised and will take the suggestion under advisement as we develop the credit market further. At this time, the Board has not found it necessary to impose the suggested “statute of limitations.”

D-35. Comment: Regulated parties (such as refiners) who are the end-users of a fuel should not be subject to a violation if they purchased either a fuel or an LCFS credit that was represented as valid. To avoid liability for actual or perceived faulty credit purchases or transfers, the purchaser would need to demonstrate good faith and proper due diligence (considered to be good business practice). To maintain the reductions required by the program, the party that generated the invalid or fraudulent credit would be required to obtain and submit valid credits to offset the shortfall. (CONOCO1)

Response: We disagree. Penalties for violations of State regulations are already set forth in statute, which provide for consideration of a number of factors, including a party’s relative culpability and other mitigating circumstances. In a violation resulting from a credit transaction, we do not know the circumstances surrounding a given violation beforehand, so it would not be appropriate to speculate on these circumstances at this time. However, as noted above, the Board’s enforcement staff’s consideration of the factors identified in State law, when assessing penalties for violations, can include a party’s due diligence and good faith efforts. See, e.g., Health and Safety Code section 42400 et seq.

D-36. Comment: We certainly understand the rationale behind the gradual phase-in embodied in the schedule. However, with the recent development of new biodiesel production technologies, and the availability of biodiesel (with carbon / intensities of less than 35) at petroleum diesel prices, there is a current opportunity to encourage much more biodiesel use in California and gain the immediate advantage of reduced GHG emissions. In fact, companies that can now switch to a B20 blend of R Power biodiesel can, with no performance or cost impacts, achieve in excess of a 12% reduction in GHG emissions almost immediately. As you know, properly made biodiesel blends can be used in standard diesel engines with no engine modifications. (RPB)

Response: The compliance schedules set forth in the regulation were established after due consideration of a number of factors, including the ability of the transportation fuels sector to provide adequate supplies of lower CI fuels in a reasonable timeframe. The regulation already encourages early introduction and/or higher volume sales of lower CI fuels, as suggested by the commenter. The regulation does this, in part, by allowing the regulated parties in those cases to generate credits that can be purchased by other parties needing the credits to comply or can be banked by the credit generators for later use/sale.

D-37. Comment: While the LCFS system does allow "banking" of carbon credits from current biodiesel sales, those credits can be later used to offset future LCFS obligations, and cannot fulfill GHG reduction targets from stationary and other significant sources. Since the LCFS reduction obligations are so gradual, banking and subsequent credit sale opportunities are limited over the first few years as they do not take full advantage of the GHG reduction needs of the greater industrial community of California. We therefore strongly recommend that any credits banked under the LCFS program be allowed to offset the carbon footprint of any GHG source in California, regardless of whether that source falls under the LCFS program or another program. Broadening the pending "Cap and Trade" system to allow LCFS credits to be used in any GHG reduction program would encourage greater reductions in GHG at lower costs, and more immediately. Additionally, harmonizing the "Cap and Trade" system in this way would reduce overlapping regulatory reporting and would strengthen these credit markets with more sales and a longer track record by the time the largest reductions in industry are phased in. If this general idea makes sense to the Board, we would be happy to work with your staff to help implement this idea. (RPB)

Response: The LCFS program already allows LCFS credits to meet other GHG reduction initiatives, such as other AB32 programs, subject to any import requirements those other initiatives may impose on the incoming LCFS credits.

D-38. Comment: We believe that LCFS should be able to build off of this existing EMTS infrastructure that a California tracking and transfer system can be implemented within a few months. In the future, it may be possible to link the programs (if built off similar platforms) so producers can track federal and state credits with one entry. We know the LCFS program staff have identified some differences between the federal and state programs, and have implied that those differences are too big to use a similar tracking platform. We disagree. The similarities greatly outweigh the differences, and we might suggest reaching out to the EMTS software developers and/or California's robust software community for ideas on how to accomplish this. (RPB)

Response: The current LCFS reporting tool is already able to retain data transactions between regulated parties. The next evolution of the reporting tool is the incorporation of a credit trading platform which will be initiated later this year. However, the EMTS and other GHG trade systems currently in the market are not necessarily designed to account for the same data such as fuel transactions or the speciation of various fuel pathways leading to differing CI values. We do appreciate the comment, and staff continues to review other software programs that are currently available to incorporate their beneficial elements into our current design.

D-39. Comment: In short, Kern respectfully but strongly suggests that any decision on adopting the proposed amendments be postponed beyond the current hearing scheduled for December 16, 2011. Kern is of this position for various reasons discussed below, all of which demonstrate that there is too much yet to be analyzed, yet to be disclosed, and yet to be decided, specifically with respect to the proposed amendments regarding high carbon intensity crude oils (HCICO). (KORC1)

Response: We disagree with the comment that adoption of the approved amendments regarding high carbon intensity crudes should be postponed. Those regulatory amendments, which are described in the sections later in this FSOR regarding the supplemental comment notices, have been evaluated, determined to be feasible, and subjected to the statutorily required public comment reviews. It should be noted that the supplemental comment periods for the approved amendments occurred after the December 16, 2011 hearing.

D-40. Comment: WSPA has concerns about the concept of permitting procedures and requirements, which govern the manner in which out-of-state biofuel producers or marketer/distributors are given the ability to opt-in as regulated parties under the LCFS. The problem with staff's proposal is that it would allow opt-ins for a producer or marketer/distributor under the LCFS without any specific ties to delivered product. This creates a potential disconnect between the opt-in parties and the regulated parties receiving the biofuel in California. Potential problems could arise where an opt-in party could claim credits for renewable fuel that was never delivered to California, or where credits could be generated for the same volume of fuel by both the opt-in party and also by a party who is acting as an importer of the fuel. (WSPA2)

Response: We disagree. The existing regulation already requires a regulated party to demonstrate to the Executive Officer's satisfaction and approval that their fuels, for which they are claiming credits, were placed into a physical pathway (i.e., delivery routes and methods) through which the regulated party reasonably expects the fuel to be transported under contract to the fuel blender, producer, importer, or provider in California. This requirement was not modified by the approved amendments; therefore, opt-in parties under the enhanced regulated party/opt-in provisions in the approved amendments would still need to satisfy the physical pathway demonstration requirements.

D-41. Comment: WSPA supports regulatory revisions that allow parties that opt-in to become the initial regulated party for the fuel under the following conditions and requirements: Opt-in parties must generate LCFS credits only through the act of bringing fuel into the state, not simply from producing it. This is vital to maintain the integrity of LCFS credit generation. An opt-in party can only sell product to another party who is either another opt-in party outside of California or a regulated party inside of California. An opt-in party is not allowed to sell product to a company who has not opted-in or who is not a regulated party. Sales from the opt-in parties to other regulated parties would be treated like any other in-state fuel transaction. Opt-in parties should be the initial regulated party for all of the fuels they deliver to California, subject to all reporting and recordkeeping requirements, as long as no previous party in the ownership chain has opted-in as-the initial regulated party for the fuel. An opt-in party must provide product transfer documentation that clearly states the product being delivered to California should not be subsequently "imported" by another party, since the original LCFS credits will be generated and claimed by the opt-in party as the initial regulated party. Such opt-ins should carry a requirement for mandatory registration of all production facilities used to supply product to California. ARB should publish a list of all parties that have elected to Opt-in so that regulated parties in California are aware of their status. Significant changes to regulated party definitions of importer and producer will require that the Guidance Document be revised to reflect these changes. WSPA requests a Compliance Workshop be held by CARB soon. (WSPA2)

Response: See Response to Comment D-31 above. With regard to publishing a list of opt-in parties, ARB staff has already published a list of all parties, including opt-in parties, registered with the LCFS Reporting Tool (LRT) as having reported fuel and/or credit transactions to date. See Table 2, http://www.arb.ca.gov/fuels/lcfs/20120625_q1datasummary.pdf, at 3. These summaries are published quarterly; the next summary will provide an updated list in Table 2 showing additional parties that have entered the program. ARB staff also intends to update the LCFS Guidance Document (http://www.arb.ca.gov/fuels/lcfs/LCFS_Guidance_%28Final_v.1.0%29.pdf) as soon as feasible to reflect the approved amendments and other appropriate updates.

D-42. Comment: Caution must be taken to avoid further disadvantage to California industry relative to global competition, competitors who import into our markets without the effect of this legislation or regulations. As the additional global capacity continues to expand, we must not erode our competitive decision by regulations that uniquely penalize the California refiners with no impact on the rest of the USA or global importers. This is a complex issue. It is too important not to get it right. Any decision can have a lasting impact on the State. I urge you to hold on this decision until you fully understand, the unintended consequences and the impact to local jobs, our employees, your citizens, and the state's economy. (PETTIGREW, TESORO)

Response: This comment provides no specific information related to the amendments or the procedures used in adopting those amendments in this rulemaking. As such, this comment is beyond the scope of the 45-day comment notice and, therefore, requires no further response.

D-43. Comment: The low carbon fuel standard should focus on its primary objective, and that is getting more low carbon fuels into the mix. (BP2)

Response: We agree. The LCFS is designed with a carbon intensity performance standard that is designed to reduce overtime to achieve a ten percent carbon intensity reduction in transportation fuels by 2020. The performance standard is already providing the incentive to spur development in lower carbon intensity fuels.

D-44. Comment: Sufficient identification should be required in order to be able to identify the producer of the credits and the date (or at least the year) the credits were produced in order to meet the requirements of the credit trading program. One example is the "carry back" program. Current year credits are not allowed to be used for compliance under this program. How are the current year credits going to be tracked to know they are not used? (WEAVER)

Response: We disagree. The amendments provide for regulated parties involved in a credit transaction to report the credit's unique identifier, if one were provided by the Executive Officer. With regard to the carry back provision, the commenter seems to misunderstand the provision. The amendments establishing the carry back provision do allow "current year" credits to be used for compliance. For example, credits generated in 2011 can be purchased by a regulated party for a limited time in 2012 and "carried back" to help meet that party's 2011 compliance obligation.

D-45. Comment: Currently the reporting tool collects data on the production facility when a reportable transaction occurs; under the proposed credit trading regulations, the agency transfers credits from one account to another when a credit trade occurs. Will the information identifying the generator of the credits and date of generation accompany the credits to the new owner's credit bank? The proposed regulations anticipate a retirement hierarchy that will be selected by the regulated party or by the Executive Officer if the regulated party does not select. Is there currently enough information being retained in the banks to differentiate between the banked credits? Will the Seller have the capability to select credits from his inventory for sale by origin of generator, date of generation, or first in first out? (WEAVER)

Response: The approved regulatory amendments specify that if the Executive Officer has provided a credit identification number to a credit holder, the credit holder must provide this number as part of a credit transfer and may specify a retirement hierarchy for credits. The Executive Officer has not yet determined if such an identification system should be established, and the detailed design and operation of such a credit identification system was not addressed in this rulemaking. If the Executive Officer establishes a system for identifying individual credits, the issues raised by these comments will be considered in that effort.

D-46. Comment: If credits purchased by an intermediate party who has purchased and sold other credits are deemed invalid, how will invalid credits be identified? (WEAVER)

Response: Invalid credits would be identified using a variety of means, including but not limited to a review of the LRT data, records the regulated parties are required to maintain, and other sources of information.

D-47. Comment: The RFS2 EMTS system provides registered parties with the capability of blocking receipts of credits from generators that they suspect may not be generating credits properly. Is that contemplated for L-CIS? (WEAVER)

Response: This suggested feature is unnecessary because ARB's credit trading process requires ARB to complete a transfer of credit from the seller to the buyer after verifying that the seller has sufficient credits in its account to cover the trade.

D-48. Comment: My understanding is that Agents approved by seller or purchaser will have capability to submit transactions for clients, but they must be registered in the program. ARB should take into consideration that Agents may have multiple clients and the registration process for Agents should be designed to accommodate that. (WEAVER)

Response: We agree and will take that comment into consideration when we fully develop the credit trading platform later this year.

D-49. Comment: As noted in the 2011 Program Review Report, ARB's preference is that all transactions are conducted through them. Hopefully, L-CIS will allow this without requiring manual intervention of ARB in the trade itself. (WEAVER)

Response: Staff is currently developing the Credit Bank and Transfer System (CBTS). This system will allow ARB to remain hands off in all trades unless a dispute is brought forth, otherwise only the buyer and seller are required for an agreement and processing.

D-50. Comment: EPA has stressed the "buyer beware" approach when purchasing RINs under the RFS program. Recently several companies received NOV's from EPA for using credits to meet obligations which the companies believed to be properly generated. Who does ARB see as the party responsible for insuring that credits under the LCFS program are properly- generated, transferred and retired? (WEAVER)

Response: ARB will validate credits generated to facilitate a credit transfer transaction, but in general credit generation, transfer, and retirement are the responsibility of the regulated parties involved.

D-51. Comment: Although some credits have been banked in the first year of the program, they are not significant enough, and it is not realistic to expect this bank to continue to grow due to large deficits to be incurred. (WSPA1)

Response: This comment addresses neither a specific amendment nor the rulemaking procedure used by the Board. As such, the comment is beyond the scope of the notice and requires no further response.

D-52. Comment: We encourage you to consider the following recommendations as minimal safeguards: Develop appropriate triggers to alert of market concerns so the program can either be halted or altered. (WSPA1)

Response: Section 95488(e) requires the Executive Officer to provide the public with specific credit and deficit information so that interested parties can keep abreast of the LCFS credit market. In this manner, ARB will also be aware of the market concerns and will propose revisions, as appropriate for addressing these concerns.

With stakeholder consultation, ARB staff is investigating the feasibility of a cost-containment flexible compliance mechanism that would be triggered under certain conditions such as a severe price swing beyond specified levels. However, development of an off-ramp mechanism such as what the commenter appears to be suggesting is not warranted at this point in the program's implementation. The Board will consider periodic updates and another formal program review from ARB staff in 2014-2015. Based on its consideration of such information, the Board can consider in a future action whether to make appropriate program adjustments or other measures to ensure the LCFS operates as effectively as possible.

D-53. Comment: WSPA request the Board ask staff to initiate a thorough analysis of the compound impacts on our industry of the various GHG reduction programs such as the AB32 cap & trade program, the inclusion of fuels under the cap, the LCFS program, and the Clean Fuels Outlet regulation amendments. (WSPA1)

Response: This comment addresses neither a specific amendment nor the rulemaking procedure used by the Board. As such, the comment is beyond the scope of the notice and requires no further response.

D-54. Comment: We encourage you to consider the following recommendations as minimal safeguards: Develop and analyze alternative approaches to reducing GHG emissions from transportation fuels that may be a better approach than the current policy. (WSPA1)

Response: This comment addresses neither a specific amendment nor the rulemaking procedure used by the Board. As such, the comment is beyond the scope of the notice and requires no further response.

D-55. Comment: In addition, in the next few years, when CARB makes practical the generation of credits from non-road, transit, and rail markets, a substantial number of new credits will enter the market to help regulated entities with their LCFS compliance. The market should be active and robust before any decision to reduce the LCFS program stringency. (SCEC)

Response: We agree.

D-56. Comment: More importantly, WSPA continues to believe that a more appropriate EER for heavy-duty spark-ignited natural gas engines (which are assumed to displace diesel fuel) is in the range of 0.7. (WSPA2)

Response: The study cited by WSPA to support an EER of 0.7 for heavy-duty, spark-ignited natural gas engines was based on the fuel economy of older, earlier generation spark-ignited, natural gas heavy-duty engines. As a result of technological advances, the fuel economy of spark-ignited, natural gas, heavy duty engines has improved, and these more efficient engines are gradually replacing the older less efficient engines. Therefore, it was appropriate to designate two different EER values to reflect the different spark-ignited and compression ignition engine technologies, with an EER value of 0.9 assigned for spark-ignited, natural gas, heavy duty engines.

D-57. Comment: Establishing an overly optimistic EER that is not representative of the existing heavy-duty CNG fleet sets up a mechanism in which LCFS credits can be generated that are not justified or real. (WSPA2)

Response: We do not agree with the premise of this comment. As discussed in response to Comment D-56, the EER value of 0.9 for these vehicles realistically represents these newer technology, spark-ignited engines.

D-58. Comment: Look-up Table for the existing fleet of CNG buses, the effective carbon intensity for this fuel/technology combination would be greater 'than that of diesel fuel, i.e., CI (North American CNG) = (68.00 / 0.7) = 97.14 gC02e/MJ Thus, these vehicles should not be part of the "Opt-In" classes of vehicles and fuels because they incur a debit for every year of the program, and this is overlooked as a result incorrectly assessing their efficiency relative to the diesel engines they displace. (WSPA2)

Response: We disagree. Allowing natural gas fueled vehicles to “opt-in” would provide an incentive for the use of natural gas, which will facilitate compliance with the regulation and encourage the use of a fuel with inherently lower greenhouse gas emissions. (See also responses to Comments D-56 and 57 for the reasons why an EER of 0.9, rather than 0.7, is appropriate).

D-59. Comment: Comparisons must be made based on on-road fuel economy rather than fuel economy derived from FTP-based laboratory testing. This is particularly important for battery electric vehicles which can be significantly impacted by ambient temperatures, use of air conditioning and heating, road grade, and other factors not typically accounted for in laboratory testing. EEA’s analysis accounted for some of these effects by using fuel economy adjustment factors recently developed by EPA to better reflect on-road operation when fuel economy is reported on fuel economy labels. (WSPA2)

Response: We disagree and believe that it is most appropriate to use the EPA's published fuel economy values for purposes of calculating the EER. The EPA values provide consumers with the best information available on the fuel economies that can be expected when consumers are deciding what type of vehicles to purchase. While under real world conditions factors such as air conditioning, heating, and ambient temperatures can affect fuel economies, these variables will not have a significant effect on the ratio of fuel economies, which is how the EER is calculated, if the same testing protocol is used to estimate the fuel economy of electric vehicles and the comparable reference gasoline vehicle. In using the EPA fuel economy values for both the electric vehicles and the comparable gasoline vehicle, we ensured that the same testing protocol was used and the same in-use operating variables were considered in the estimation of the fuel economies for both electric vehicles and the comparable gasoline vehicles.

D-60. Comment: CARB should monitor on-road fuel economy of electric vehicle technology and make adjustments to EERs where necessary. (WSPA2)

D-61. Comment: WSPA disagrees with ARB staff’s selection of the reference vehicle when assessing the EER of the Chevrolet Volt. ARB has chosen the Chevrolet Cruze as the reference vehicle in this case, which has a fuel economy of 28.3 mpg. Thus, ARB has estimated an EER of 93 mpgge /28.3 mpg = 3.29. A more direct, and a more appropriate, way to estimate the EER for a PHEV is to simply take the ratio of fuel economy under gasoline mode versus electric-only mode. As noted above, the electricity-only fuel economy is reported on the label to be 93 mpgge, while the label value for gasoline mode is 37 mpg which results in an EER of2,5 for PHEVs (i.e., 93 mpg/37 mpg). This approach has a significant technical advantage because there is there is no need to try to match vehicle attributes (i.e., performance, mass, cabin volume, etc.) because it is the same vehicle. (WSPA2)

Response: We disagree with the commenter's suggestion. The purpose of the EER is to recognize the energy that is saved when someone decides to purchase and drive a plug-in hybrid vehicle (PHEV) in the electric mode instead of a gasoline vehicle. The use of the EER recognizes the amount of gasoline that is saved when the vehicle is using grid generated electricity. Therefore, the most realistic and appropriate assumption would be that a consumer is driving a gasoline car of about the same size and characteristics as the PHEV before deciding to replace it with a PHEV. The use of the fuel economy value of the Volt operating in the gasoline mode in the calculation of the EER would not recognize the true energy savings that occur when someone purchases and drives a Volt. Because the Chevrolet Cruze is the vehicle closest in size and vehicle characteristics to the Chevrolet Volt, it is for this reason that the Cruze was used as the reference vehicle in the EER calculation for the Volt. The use of the fuel economy of the Cruze in the calculation of the EER for the Volt most accurately recognizes the true amount of gasoline that is displaced by electricity, and the accompanying fuel savings, that occur when someone replaces a gasoline vehicle with a Volt and operates it in the electric mode.

The Board found in Resolution 11-39 that the amendments were developed using the best available scientific information. However, as more data become available, we intend to monitor both the on-road and published fuel economy of electric vehicles, making appropriate adjustments to the EER values in the regulation as necessary and warranted by the data.

D-62. Comment: By using a conventional gasoline vehicle as the reference vehicle, ARB is effectively assigning credit to the hybrid powertrain of PHEVs. Since conventional hybrid vehicles (i.e., those that are not recharged with grid electricity) do not receive a credit via the EER, a PHEV operating in gasoline mode should not either. (WSPA2)

Response: We disagree. The purpose of the EER for PHEVs is to estimate the amount of gasoline that is displaced by grid-generated electricity when the vehicle operates in the electric mode. By using a conventional gasoline vehicle as the reference vehicle, and the fuel economy of the PHEV in the purely electric mode, we can calculate the amount of gasoline that is displaced by grid-generated electricity, and the accompanying energy savings, that result from the decision of the consumer to drive a PHEV instead of driving a conventional gasoline vehicle. We agree that a PHEV operating in the gasoline mode should not receive any credit because it does not use any grid-generated electricity. The regulation's credit and EER calculations recognize this, and provide credit only for the amount of grid-generated electricity used by PHEVs. It is for this reason that the fuel economy of the PHEV in the electric mode only, in combination with the fuel economy of a conventional gasoline vehicle, is used to calculate the EER for PHEVs. This EER is used with the amount of grid electricity used by PHEVs to calculate the credit resulting from the amount of gasoline displaced by grid-generated electricity.

D-63. Comment: We recommend that ARB management establish a process for direct dialogue between labor and ARB, potentially through the BGA process, to ensure concerns or questions can be addressed on an on-going basis as AB32 is implemented. (BGA1)

Response: Because this comment addresses AB 32 in general and not the LCFS amendments specifically, it is outside the scope of the notice and requires no further response.

D-64. Comment: We also recommend that ARB form a work group to identify and evaluate potential projects in California to reduce emissions at oil production facilities as well as investments that can be made in refineries to produce cleaner, renewable fuels. We believe California can become a major producer and exporter of clean fuel products, even as it moves to provide cleaner gasoline and diesel to markets here and abroad. (BGA1)

Response: Because this comment addresses the LCFS in general rather than the specific amendments, it is outside the scope of the notice and requires no further response.

D-65. Comment: We also recommend that ARB form a work group to identify and evaluate potential projects in California to reduce emissions at oil production facilities as well as investments that can be made in refineries to produce cleaner, renewable fuels. We believe California can become a major producer and exporter of clean fuel products, even as it moves to provide cleaner gasoline and diesel to markets here and abroad. (BGA1)

Response: Staff will investigate the potential for a work group but there may be other programs that are currently in place in which the information can be obtained.

D-66. Comment: Yes. I think one of the things we recommended is that information be provided to the Energy Commission under a PRA request. You can imagine how competitive this marketplace is. All of these refiners certainly have their own business plans and cannot get together and discuss these issues. Through the Energy Commission is the best way to keep that data confidential, but make it available to the Air Resources Board for any additional analysis. (WSPA3)

Response: We will continue to work with CEC to conduct our analyses when the individual refiners are unable to provide individual responses because they lack the information or are bound from sharing their data for business confidentially purposes.

E. Economic Analysis

E-1. Comment: Given that we aren't even sure that there will be sufficient blending stocks to comply with this measure, why are we moving forward? Would it hurt to do more research on how this regulation could actually be successful before pushing an extremely costly burden on an economically crippled region? Fuel prices account for a larger portion of our budgets than they ever have, yet we are thinking of ways to increase them further during the largest recession we've seen in our generation. We all want clean air and we all want to find ways to become more independent in our fuel supply. Please reconsider more attainable and achievable goals for this regulation. (OSD)

E-2. Comment: Western State Petroleum Association (WSAP) has two main comments on fuel supply and feasibility of program in terms of low CI fuel.

1. In addition to concern about low CI fuels supply is the issue of cost. CARB staff's "illustrative compliance scenarios" do not include the economic costs associated with each scenario. CEC indicated the scenarios include unrealistic assumptions about volumes of cellulosic fuels and "drop-in" fuels coming to CA (greater than 50% of U.S. supply) to show compliance in the middle years of the program but this still would not achieve 2020 compliance. Costs were estimated at approx. $1B/yr in 2016 ramping up to $4.5B in 2020 and $9B in 2024.

2. WSPA requests the Board ask staff to include an annual review of the program's health that would include a public process and a formal report to the Board. At a minimum, topics to be included in the analysis would be the feasibility of the program in terms of low CI fuel and credit availability as well as costs and impacts of the program. This review would be required to incorporate analysis conducted by the California Energy Commission on current and projected energy supply and costs impacts. (WSPA1)

E-3. Comment: Our reason for immediate suspension is that there is entirely missing assessment on how this program will affect the price of fuel to California motorists.

Beyond these more-pragmatic examples, we contend that CARB has NOT performed an adequate economic impact assessment of the LCFS. There has, to date, been no calculation or estimate of what the cost per gallon might be to California motorists. This is a major failing and needs to be corrected immediately. Recently the California Energy Commission took a first-step assessment of LCFS costs to refiners and found that the LCFS could cost fuel providers nearly $3 billion in 2018, nearly $4 billion in 2019 and approximately $4.5 billion in 2020. This expense will be passed on to fuel consumers. This analysis does not include the potential inflated cost of LCFS credits due to lack of "low-carbon" fuel, nor does it include other major costs to refiners such as the "cap & trade" carbon tax, or the escalating AB 32 administrative assessments. CARB is legally obligated to disclose such information to the public and certainly its Board members. (CIOMA)

E-4. Comment: Fueling California (FC) made the following comments on higher fuel costs, economy, fuel supply constraints, and expensive LCFS regulations:

1. A November 14, 2011 independent cost analysis by the California Energy Commission (CEC) concluded that under CARB's "high petroleum price" scenario the LCFS would make California fuel more expensive by nearly $3 billion in 2018, nearly $4 billion in 2019 and approximately $4.5 billion in 2020. The CEC's analysis also indicates that LCFS program costs may reach as much as $9 billion by 2024/2025. Further, the CEC also concluded that costs are likely to rise even further should other states adopt LCFS regulations (22 states are currently considering such programs). The billions of dollars in projected LCFS costs will not fall on fuel providers, but will dramatically increase costs for businesses in all sectors that rely either directly or indirectly on energy, and consumers in the form of higher fuel costs and increased costs for fuel-dependent goods and services.

2. Higher fuel costs directly translate to job loss. As energy costs increase, economic activity slows, creating job losses during a time when California suffers from the second-highest unemployment rate in the nation at 11.2 percent. Additionally, as prices of fuel-related goods and services will rise, consumers will spend less, further weakening and delaying California's economic recovery.

3. California already has the most differentiated fuel blend mix in the nation, and adding one more layer onto an already complex mix will likely lead to ever greater additional cost and, most troubling, increased risk of supply disruptions/outages and threat of prolonged periods of price spikes. The CEC's LCFS report analysis raised concerns about the availability of biodiesel, the feasibility of corn-oil biodiesel in 2017 and beyond, the supply or renewable diesel and the feasibility of using half the U.S. supply of cellulosic fuels in 2018 and beyond.

4. California already has numerous laws and regulations aimed at reducing Greenhouse Gas emissions, such as AB 32, CARB's Clean Car Standards and the state's Renewable Portfolio Standard (RPS) that are expensive to implement, hampering job creation, and pressuring economic recovery. The cost of the LCFS alone will impose severe financial burdens on California's economy, but combined with other recently adopted regulations will have additional, additive negative economic impact. Energy costs are already escalating dramatically under AB 32 and the state's RPS. Implementing another expensive layer—the LCFS—on top of these further complicates the

interplay among all the various regulatory programs, likely leading to conflicts among the different policy frameworks and increasing the likelihood of negative unintended consequences.

Given these concerns about fuel cost, supply, and feasibility of implementation, we encourage ARB to consider the following:

- First, the ARB needs to give serious consideration to the CEC's analysis and adjust its own projections and rule elements accordingly.

- Further, engage the CEC to independently analyze the economic impacts of the LCFS (both in isolation and in combination with the other regulations previously cited) on the cost and reliability of fuels, in view of its unparalleled expertise in fuel supply issues, conducting independent analysis of economic impacts and true fully burdened Cost-Benefit analysis during a time of economic crisis. (FC)

E-5. **Comment:** COALITION - the undersigned organizations representing fuel providers, employers, large, small and minority-owned businesses, fuel users and taxpayers, continue to have serious concerns about the California Air Resources Board's implementation of the Low Carbon Fuel Standard (LCFS) regulation. Following concerns are based on higher fuel costs, hidden taxes on consumers, jobless economy, cost of other regulations and no net reduction in Greenhouse Gas emissions.

1. The CEC's November 14 analysis indicated that under the high petroleum price scenario the LCFS could cost fuel providers nearly $3 billion in 2018, nearly $4 billion in 2019 and approximately $4.5 billion in 2020. This study also raised questions about the feasibility of biodiesel and corn-oil biodiesel, the supply of renewable diesel and the feasibility of using half of the U.S. supply of cellulosic fuels in 2018 and beyond. Equally disturbing is the CEC's conclusion that because of increased demand for advanced biofuels, costs are likely to rise even further should other states adopt LCFS regulations.

2. The billions of dollars in projected LCFS costs will not fall only on fuel providers, but will dramatically increase cost for businesses in all sectors, and constitute a hidden fuel tax on consumers in the form of higher fuel costs and increased costs for fuel-dependent goods and services. Higher costs translate to loss of jobs, which is unconscionable considering that at 11.7 percent, California's jobless rate is second-highest in the nation.

3. The cost of the LCFS alone will impose severe financial burdens on California's economy, but combined with other costly regulations will have a devastating impact. Energy costs are already escalating dramatically under AB 32 and the state's renewable portfolio standard; our economy cannot sustain billions more on top of those increases.

E-6. **Comment:** Members of California Biotechnology Industry Organization (BIO) believes that LCFS should be incentivized in advanced biofuels as part of the solution to a low-carbon economy. ARB should conduct a more comprehensive economic analysis in 2012. Ensure that the anticipated pricing mechanism is defined in a way that educates market players as to how carbon intensity (CI) values will create a differential value. Include scenarios with cellulosic numbers that are greater than Energy Information Administration (EIA) values. (BIO)

E-7. **Comment:** Initiate a thorough analysis of the potential cumulative impacts on the cost and availability of transportation fuels and on the sector in California from numerous climate change regulations being implemented by ARB. What will weaken and destroy the LCFS is a program that is constructed on too aggressive a timeframe for the realistic availability of low carbon fuels and vehicles and infrastructure, fuel markets that are disrupted, and California suffering economic burdens it can ill afford. (WSPA2)

E-8. **Comment:** Will the costs of the implementation truly outweigh its benefits? It is apparent that it will cost a significant amount of money to achieve the stated goals as the standard is currently laid out. What is troublesome is that a definitive answer as to what is to be accomplished has yet to be answered. Whatever it is, the costs will ultimately be passed on to consumers. How much of an increase will they pay at the pump? Is it realistic to expect consumers to pay these increases with the current economy in such an unstable state? River City Petroleum therefore requests the implementation of the Low Carbon Fuel Standard be postponed until all costs and benefits of the program are weighed out and a more accurate measurement of them are able to be derived. (RCP)

E-9. **Comment:** As a whole, the U.S. industry has been able to compete with our global competitors supported by our exceptional employees' engagement and productivity. But recent announcements of refinery shutdowns and employee layoffs on the east coast should serve as a reminder to us about how sensitive regulation and industry and the care we must take to ensure we remain competitive.

Our ability to remain competitive is important to our employees, your citizens, and the state of California. Our industry directly employs 15,000 California workers with average annual compensation of nearly $100,000. The combined direct and indirect employment is estimated to exceed 125,000 employees with jobs in local communities where we operate. These are good jobs, allowing our employees to support families and contribute to local communities. (TESORO)

E-10. **Comment:** We are not asking CARB to abandon the standard, rather asking CARB to take some reasonable steps to really ensure this program doesn't disrupt the transportation fuels markets, or injure the California economy. (WSPA3)

E-11. **Comment:** we're concerned first and foremost with energy affordability. So we look at the CEC's estimate of additional cost—of additional cost and expressed great concern.

Furthermore, on the restrictions on carbon intensity of fuels, we're concerned that will increase our reliance on imported fuel, which will raise cost, kill jobs, and jeopardize our energy security.

We're also concerned about the civil rights impacts and that higher gas price will disproportionately harm the poor and the working poor.

To the extent that this plan relies on biofuels such as ethanol, we're concerned that worldwide food shortages will be increased and even starvation in the third world, which I would remind you the riots in the Middle East were a result of rising food prices. So when we start to burn food for fuel, you wind up with less food for people in the third world and higher prices. (CEU2)

E12. **Comment:** Sign the petition to the California Air Resources Board opposing the "low carbon fuel standard" plan to raise gas prices:

WHEREAS: Low carbon fuel standard represents costly new regulations that are estimated by the California Energy Commission to raise gas prices a total of $3 billion in 2018, $4 billion in 2019 and $4.5 billion by 2020.

WHEREAS: The low carbon fuel standard relies on biofuel mandates that have been criticized both by advocates for job creation and leading environmentalists.

WHEREAS: California's current 66¢ per gallon gas taxes are already the highest in the nation. With gas prices at record highs we do not need even higher gas prices.

WHEREAS: Gas price increases harm those who can least afford them the most.

WHEREAS: Higher transportation costs raise the price of things we all buy every day and will kill jobs in the transportation industry.

WHEREAS: Food cost will rise further because biofuel requires the burning of food for fuel.

WHEREAS: Worldwide increases in the price of food staples is one consequence of biofuel use in Western countries. Biofuel use worsens hunger in the Third World and has been condemned by elected leaders in Africa.

BE IT RESOLVED: High gas prices are already hurting working people at the pump and putting jobs in jeopardy. Low carbon fuel standard is another bad idea to raise costs at the worst possible time. (CEU1)

Response: All these comments address general aspects of the original 2009 LCFS rulemaking and not the specific amendments adopted by the Board in the current rulemaking. As such, they fall outside the scope of the 45-day notice. We should note that the "Economic Impacts" chapter of the 2009 LCFS Initial Statement of Reasons (ISOR) was not revised or updated under the current rulemaking. The conclusions reached in that chapter were available for public comment during the original 2009 rulemaking. All comments on the economic impacts of that rulemaking were responded to in the Final Statement of Reasons for the 2009 rulemaking. As such, the Board's findings regarding the economic impacts of the original LCFS regulation are not subject to comment under the current rulemaking.

The 2011 rulemaking adopted only incremental changes from the original, approved LCFS regulation. Only these amendments are subject to comment in the current rulemaking process. Accordingly, the Board found in Resolution 11-39 that the amendments will have no significant adverse economic impacts. This finding, along with the supporting analysis, was released for public comment under the current rulemaking.

E-13. **Comment:** Has CARB assessed the economic impacts of the LCFS, including the extent of the potential costs of LCFS reporting? The impact of the reporting requirements on regulated parties is unclear. (NRC)

Response: The Board's conclusions regarding the economic impacts of the LCFS amendments appear in Chapter VI ("Economic Impact Analysis") of the Initial Statement of Reasons. The Board found that, with one exception, the amendments would have no impact on reporting costs. The exception is in the area of crude oil carbon-intensity reporting. Under the original provisions, producers would have to determine the CIs of high carbon intensity crude oils they purchase. Under the amended provisions, ARB staff would calculate the CIs for use in calculating the annual average California crude oil CI. This change would relieve petroleum producers of the need to perform an analysis which costs an estimated $20,000 per high carbon intensity crude oil. Since 65 crudes did not pass an initial screening process designed to identify non-high-carbon intensity crudes, the industry-wide savings would be as high as $1.3 million. Full LCFS reporting costs were not discussed in this analysis for reasons discussed in the response to comments E1 through E12, above.

F. Method 2A/2B

F-1. **Comment:** The GREET standards used for the Low Carbon Fuel Standard (LCFS) do not correctly account for fugitive natural gas emissions and other Greenhouse Gas (GHG) emissions (PSPC/EDLA).

1. CARB still uses a methane carbon intensity of 25 times CO_2, instead of the latest science saying it is 34 over 100 years or 105 over the next crucial 20 years, as shown in the paper by Drew T. Shindell, et al., "Improved Attribution of Climate Forcing to Emissions," Science 326, 716 (2009). When will CARB use the latest science? (PSPC/EDLA)

2. The latest science says that methane produced by fracking has more fugitive emissions than conventional natural gas, which should be included in any LCFS for methane produced by fracking. The paper by Howarth, et al., says fracking "methane emissions are at least 30 Percent more than and perhaps more than twice as great as those from conventional gas. See attached paper, "Methane and the greenhouse-gas footprint of natural gas from shale formations," Climatic Change (2011) 106:679-690, downloadable from: DOI 10.1007/s10584-011-0061-5. (PSPC/EDLA)

3. GHG emissions from aged natural gas engines are considerably more than new engines, and should be included in the calculations. The paper by Melendez, et al., indicates in Fig. 14 on p. 22 that older natural gas engines could emit as much as 50 percent more emissions than new buses. See attached paper, "Emission Testing of Washington Metropolitan Area Transit Authority (WMATA) Natural Gas and Diesel Transit Buses," downloadable from: http://www.afdc.energy.gov/afdc/pdfs/36355.pdf. (PSPC/EDLA)

   This is off by orders magnitude when combined and at the very least by several factors. Example, in CARB February 27, 2009 GREET for CNG a "placeholder" figure of 0.0375 grams methane per mile is used for natural gas emissions while the CARB papers send for review of this issue on Washington D.C CNG buses sent by Michael Benjamin & vis-à-vis Cody Livingston documents from 10 to 17+ grams CH_4 emitted per mile [*the full meaning of this sentence is unclear; it is changed here very little from the original*]. More recently, the April 2010 study of natural gas GHG methane emissions provided by SCAQMD has data of from 40 to 100 grams CH_4 per mile emitted for heavy duty vehicles. Suspiciously, the same number was used for nitrous oxide (N_2O) of 0.0375 grams emitted per mile. This is off by over 100 to 1,000 times the number used by CARB staff and nothing was done about it when brought up to staff on the record or by the Expert Work Group (several times). This will all be documented in detail in future litigation following CARB's Board decision not addressing these issues. (PSPC)

4. CARB has failed to account for even the EPA acknowledged 75 percent fugitive emissions related to methane (CH_4) from landfills (and it is probably more than 75 percent over the full life of a landfill), as compared to methane from contained anaerobic digesters of waste with zero percent fugitive emissions. See attached paper by Jim R. Stewart, "Landfill Gas-to-Energy Projects May Release More Greenhouse Gases than Flaring." (PSPC/EDLA)

Response: We did not propose amendments related to fugitive natural gas emissions in the 45-day Notice for this rulemaking. For this reason, the issues raised in this comment are beyond the scope of the current rulemaking and therefore require no further response.

F-2. Comment: The industry is also growing in ways we never considered, such as the recent strong interest in advanced biofuels from the U.S. military. California, in particular, is a center for companies that are leading the effort to provide the U.S. military with low-carbon, domestically produced biofuels for jets and ships. Algal and sugar-based biofuels are being researched and developed in California by companies such as Solazyme, Sapphire Energy, and Amyris with assistance from federal programs. Since California is home to many military installations, this national effort will benefit the State. CARB should thus take care to ensure pathway availability for new and innovative technologies, such as military biofuels. (BIO)

Response: A stated goal of the LCFS is to incent the development of new low-carbon fuels (see page V-2 of the 2009 LCFS Final Statement of Reasons, for example). The certification program proposed in Section 95486(f) of the proposed amendments will expedite and facilitate the approval of fuels such as those mentioned in the comment.

F-3. Comment: The method 2A and 2B certification process versus regulation will help to speed the implementation of innovative ideas. There is a lot of work going on advanced feedstocks and technologies that we're going to see over the next ten years. And, I think without sacrificing anything in terms of the quality of review, we can get rid of a lot of the regulatory baggage by going through the certification process. (BIODICO)

Response: We agree that the certification process added to section 95486(f) will expedite the approval of new fuel pathways without sacrificing any of the rigor of the pathway review process. A better defined, more systematic review process such as the amendment's certification program will increase the rigor of the pathway review process. The result will be improvements in the efficiency with which new low-carbon fuels enter the California market.

F-4. Comment: While we appreciate CARB's consideration of some of our previous comments regarding certain elements of the proposed certification program, we still believe several proposed elements of the process are redundant, excessively burdensome and/or would add little or no value to CARB's evaluation of applications. As currently constructed, the proposed certification program would likely discourage potential applicants from pursuing new pathway approval due to excessive burden of gathering the required information. (RFA)

Response: Although the certification program does require applicants to fully document their proposed pathways, it does not contain redundant submission requirements. Nor did the commenters provide any examples of requirements they consider to be redundant. The certification process requires full documentation because it considers applications from a variety of fuel producers employing an even wider variety of production methods. As such, we cannot approve pathway proposals unless we have sufficient documentation on file to demonstrate that our decisions are based on concrete, verified information about the proposed pathways. When a question is raised about the basis of a fuel pathway certification, we must be able to demonstrate that we performed a careful and thorough evaluation—one that included verifying, to the extent possible, the information and data submitted by the applicant.

F-5. In addition, the proposed requirement to provide two years' worth of invoices for energy purchases is onerous and unnecessary, given that applicants attest to the accuracy of the energy usage values recorded in their CA-GREET analysis and associated lifecycle analysis report. CARB's proposed certification program for Method 2A/2B applications clearly requires applicants to attest to the veracity and accuracy of the information submitted, including all inputs to the CA-GREET model. Therefore, it is duplicative and unnecessary to require applicants to submit two years' worth of energy invoices when energy use is already documented and attested to in the compulsory CA-GREET analysis, lifecycle analysis report, and other required information. If CARB continues to believe this information is necessary, it should revise the language to require only a representative sample of energy invoices from the last two years, or to require submittal of this information only on an as-needed basis. The requirement for two years' worth of transportation invoices is similarly onerous and unnecessary. (RFA)

Response: The certification process requires energy receipts covering two years of production primarily to reduce the possibility of basing a pathway CI on an anomalous period of operation. A single year might not be representative of ongoing, long-term operations. Although unrepresentative two-year periods are also possible, they occur less frequently than atypical one-year periods. Applicants are asked to select a period that is representative of long-term, stable operations, even if it is not the most recent period. The period chosen should ultimately be one that will produce a CI that would stand up in a future audit of the plant’s energy consumption and GHG emissions.

It should be noted that exceptions can be made to this two-year rule when representative data covering two years are not available. If the applicant’s plant hasn’t operated for two full years, or if operational problems have reduced the period of stable representative operations to less than two years, ARB staff will work with the applicant to identify an appropriate time period for which receipts must be submitted.

The commenter argues that energy receipts covering two years of operations are unnecessary because applicants must attest to the accuracy of the energy consumption values they report. In a public certification process, letters of attestation from producers (especially out-of-state producers) are of limited value. Such letters are quite useful in facility audits and investigations, but cannot serve as the basis for certifications. By definition, certification decisions are to be based on well-documented quantitative data. In approving a certification application, the Executive Officer must be able to demonstrate to the public that his/her decision is based on solid evidence of actual plant energy consumption.

Finally, transportation invoices are only required when applicants report non-default transport modes or distances. Invoices are not required if CA-GREET default values are used to calculate the pathway CI.

F-6. Still, we feel compelled to point out that biofuel producers rarely have knowledge of the exact points of origin of their feedstock and the geographic boundaries from which the feedstock was sourced, nor do they have detailed knowledge of the agricultural practices used to produce the crops. Requiring applicants to describe the origin of their feedstock in detail is impractical and unreasonable, particularly because CARB does not readily allow Method 2 applicants to receive credit for low-intensity agricultural practices. (RFA)

Response: Section 95486 (f)(3)(C)2.a.ii in the amendments specify that applicants are to submit detailed information on feedstock production. This requirement was not meant to apply, however, to applicants using default CA-GREET input parameters for calculating feedstock production emissions. This section of the modified regulation order was clarified to make this exception explicit.

F-7. In addition, we believe CARB should allow the use of the default values in the latest version of the Argonne (DOE) GREET model because it contains more current data on agricultural practices than what appears in the CA-GREET. (RFA)

Response: The Board in Resolution 09-31 has already directed the Executive Officer to revise the incorporated GREET model (CA-GREET) as newer models become available. Accordingly, ARB staff are continuing to monitor developments and upgrades to the GREET model to determine if and when such revisions to CA-GREET are warranted.

G. Future Work

<u>Indirect Land Use Change</u>

G-1. **Comment:** The unique obligation of biofuels developers to account for indirect land use change emissions (which the National Research Council recently described as highly uncertain) and supplemental environmental reporting requirements proposed by the LCFS Sustainability Working Group are two examples of program elements that could inhibit deployment of promising technology. We urge CARB to work with BIO to ensure that the LCFS sends a clear signal to investors of California's support for low-carbon advanced biofuels. (BIO)

G-2. **Comment:** In addition, we believe that the adoption of sustainability criteria is a better way to deal with indirect land use change (iLUC) effects than the imposition of highly uncertain factors on biofuels. We are concerned that highly uncertain ILUC factors would do very little to address the underlying problems associated with ILUC but could instead create negative, unintended consequences such as greater ILUC risks and increased costs to consumers. (SHELL)

G-3. **Comment:** CARB staff notified all LCFS stakeholders that they did not believe that there was sufficient time to address two significant issues originally proposed for this rulemaking—Low-Energy Use Refiners and indirect Land Use changes. As a result, CARB staff proposed a subsequent rulemaking in 2012 to address these issues with the intent of both rulemakings becoming effective simultaneously in 2013. We believe that conducting such a bifurcated rulemaking increases the difficulty in determining how all the regulatory pieces will eventually fit together and on predicting how these amendments, when enacted piecemeal, will actually affect Paramount's operations in the future. (PPC)

G-4. **Comment:** The AEC encourages CARB to move quickly to adopt the latest science with regard to land use change. As you know, the regulation's treatment of indirect land use change (ILUC) is the single-most controversial aspect of the regulation. CARB Resolution 10-49 recognized this reality, and set the rulemaking on a path to close the data gaps and explore the indirect effects of other fuels. While CARB's focus to date has been on the land use impacts of conventional biofuels, the lack of resolution of this issue has caused considerable uncertainty with regard to the predictability and durability of the regulation.

There were also preliminary land use change model runs conducted for cellulosic ethanol but they have not yet been finalized or formalized. While we commend the CARB staff for processing a tremendous amount of technical work in time to include the LCFS as an Early Action Measure, we hope we can resolve the major questions about land use change (many of which transfer over into advanced ethanol production) as expeditiously as possible, and not later than the new deadlines likely adopted this week. (AEC)

G-5. **Comment:** The AEC encourages CARB staff to refocus its effort on the critical issue of indirect effects of other fuels. As is the case with land use change, we believe it is important to view the issue of "indirect effects of other fuels" as one that can undercut the credibility and durability of the program. The LCFS Expert Workgroup published a clear analysis of the issue and possible resolution roughly 12 months ago. The importance of consistency with regard to carbon accounting is often misunderstood. First, consistency is very likely critical to the credibility, durability and success of the program here and abroad. But consistent carbon accounting also gives investors and project developers a framework for assessing the value of their fuel relative to other fuels even with the number of data gaps and uncertainties associated with measuring supply-chain emissions and second-order effects. Inconsistent carbon accounting adds an additional layer of uncertainty and risk by virtue of the fact that asymmetrical and/or unsettled methodologies could shift at any time. We encourage CARB staff to reprioritize some of the issues contained in the EWG report. More specifically, the AEC recommends that CARB commit to a process to assess the marginal, indirect effects of all fuels so that investors and fuel developers see that all fuels will ultimately be assessed in the same way. (AEC)

G-6. **Comment:** As stated in our Advisory Panel comments of November 17, 2011, we believe achieving CI reductions of the magnitude assumed by ARB would require a reduction of the ILUC penalty for corn ethanol to the levels recently estimated (i.e., 10-14 *g/MJ)* by Tyner et al. (July 2010) and Laborde (October 2011). As evidenced by ARB's own revised compliance scenarios, we believe a failure to reduce corn ethanol ILUC values *soon* will greatly strain the ability of regulated parties to comply with the LCFS as the CI reduction requirements become more stringent in 2012 and beyond. (RFA)

G-7. **Comment:** While RFA supports some of CARB's proposed revisions to the existing ILUC analysis, as outlined at a September 14, 2011 CARB workshop, we remain opposed to several planned changes that are scientifically unsupported and go against the recommendations of the LCFS Expert Work Group. We commented in depth on the September 14 ILUC workshop in comments dated October 5, 2011, and we incorporate those comments here by reference. (RFA)

G-8. **Comment:** Finally, I know it's controversial, but the indirect land use impact changes cut both ways in our industry. It depends upon what feedstock that you're making the biodiesel from.

We happen to use yellow grease and non-food products that are produced locally in California. But I would urge staff to continue in the direction that they have been going which is to apply the best available science and data. Thank you. (BIODICO)

Response: We did not propose amendments to land use change in the 45-day Notice for this rulemaking. For this reason, comments received that are related to land use change are outside the scope of the 45-day Notice for the current rulemaking. Work is in progress for the land use change analysis and ARB staff plans to return to the Board at a later date to propose amendments to land use change.

<u>Sustainability</u>

G-9. **Comment:** Resolution 09-31 directed the Executive Officer to work with stakeholders to develop a work-plan for sustainability provisions that would be used in implementing the LCFS regulation by December, 2009, and to complete the tasks contained within the work-plan by December, 2011. The SWG has made significant progress in developing a science-based definition of sustainability and the specific provisions to be included in the LCFS regulation. However, the work-plan includes additional components that have not yet been addressed, specifically: 1) how the sustainability provisions can incentivize sustainable fuels; 2) what provisions will be reviewed for inclusion in the LCFS regulation; 3) the framework for how sustainability provisions should be incorporated and enforced in the LCFS program; and 4) a schedule for finalizing the sustainability provisions. Additional work is needed to complete these elements. NRDC supports the continuation of this important work and respectfully requests that the Board extend the December, 2011 deadline to allow the SWG to address these issues and complete this critical process. (NRDC1)

G-10. Comment: Resolution 09-31 directed the Executive Officer to work with stakeholders to develop a workplan for sustainability provisions that would be used in implementing the LCFS regulation by December, 2009, and to complete the tasks contained within the work plan by December, 2011. Over the past year, the Sustainability Work Group has made progress in developing sustainability provisions for the LCFS, but much work remains to be done to fully develop the criteria and reporting mechanisms necessary for ensuring the LCFS program does not include or incentivize actions that would result in adverse environmental impacts. More time is also needed to solicit and incorporate feedback from the public who have interests in protecting ecosystems and wildlife habitat but may not have been aware of the potential for the LCFS program to affect the environment beyond the impacts of industrial energy operations and greenhouse gas emissions. (CBD)

G-11. Comment: The important efforts of the Sustainability Work Group should continue. (NRDC1)

Response: Because sustainability provisions were not proposed as part of the 45-day Notice for the current amendments, these comments are beyond the scope of this rulemaking. With that said, we agree and extended the December 2011 deadline to continue working on sustainability provisions. The work that the LCFS Sustainability Working Group had accomplished by the deadline had not yet fully covered issues related to incentives, how sustainability provisions could be implemented and enforced in the LCFS program, or a schedule for finalizing sustainability provisions. We will continue to solicit interested stakeholders to participate in the LCFS Sustainability Workgroup's efforts.

G-12. Comment: Supplemental environmental sustainability reporting requirements proposed by the LCFS Sustainability Working Group could inhibit deployment of promising technology solutions. (BIO)

Response: We are working with stakeholders to develop sustainability provisions that will be inclusive of the three pillars of sustainability: environmental, social, and economical.

G-13. Comment: We continue to advocate for the adoption of internationally agreed/aligned sustainability criteria for biofuels. (SHELL)

Response: We have been closely following international sustainability efforts throughout this process and will continue to consider ways to incorporate accepted criteria into our sustainability provisions.

G-14. Comment: Believe that implementation of sustainability criteria is a better way to deal with iLUC than highly uncertain factors on biofuels. (SHELL)

Response: Neither sustainability criteria nor iLUC amendments were proposed in the 45-day notice for the current rulemaking. ARB staff has only discussed sustainability provisions and not proposed any regulations related to sustainability criteria for biofuels. Also, the development of sustainability criteria and iLUC are two different aspects of biofuel production and are treated separately under the LCFS. For these reasons, this comment is outside the scope of the 45-day Notice for the current rulemaking.

Low Energy Use Refineries

G-15. Comment: Our comments spotlight the concept of Low-Energy Use Refiners and the need to not lump these types of facilities in with the massive 200,000 barrel a day refineries that these regulations were truly designed to regulate. This issue was discussed with staff numerous times including prior to the 45-day notice, but our request for changes to the proposed regulations was subsequently left out of the package and deferred until a proposed subsequent rulemaking in 2012. We believe that conducting such a bifurcated rulemaking increases the difficulty in determining how all the regulatory pieces will eventually fit together and on predicting how these amendments, when enacted piecemeal, will actually affect Paramount's operations in the future. Paramount respectfully requests that the adopting resolution for these amendments contain sufficient language to keep this very important issue on the 2012 LCFS regulatory agenda. (PPC)

Response: While this comment is outside the scope of the 45-Day Notice, we should note that Resolution 11-39 was drafted to incorporate the commenter’s suggestion. Specifically, the Resolution directs the Executive Officer to work with interested stakeholders to investigate the feasibility of developing into regulatory language for a future rulemaking(s) a number of different concepts, including a concept that accounts for lifecycle carbon intensity associated with low-energy refineries.

<u>Program Review</u>

G-16. Comment: Conduct annual reviews and analysis of LCFS program feasibility and costs in order to make needed adjustments. (WSPA1)

G-17. Comment: WSPA requests the Board ask staff to include an annual review of the program's health that would include a public process and a formal report to the Board. At a minimum, topics to be included in the analysis would be the feasibility of the program in terms of low carbon intensity fuel and credit availability as well as costs and impacts of the program. (WSPA1, WSPA2)

G-18. Comment: WSPA is not asking that the LCFS be abandoned at this time. We're asking that ARB conduct annual reviews of the program's feasibility and costs and make adjustments if needed. That is not a request to weaken the LCFS program. (WSPA2)

G-19. Comment: This review would be required to incorporate analysis conducted by the California Energy Commission on current and projected energy supply and costs impact. (WSPA1, WSPA2)

G-20. Comment: Establish an annual review requirement that receives formal input from the CEC, and includes a trigger mechanism to make expedient changes should problems with implementation arise. (COALITION)

Response: Consideration of formal annual reviews is outside the scope of the 45-day Notice. Nevertheless, ARB staff will continue to work with stakeholders on informal reviews, and staff will provide updates to the Board periodically prior to the next formal review, which is due by January 2015.

IV. SUMMARY OF COMMENTS MADE DURING THE FIRST 15-DAY COMMENT PERIOD AND RESPONSES

A. List of Commenters

The table below identifies the five comments received during the first 15-day comment period. It provides a correlation between (1) the abbreviation used in this Section V to refer to a comment letter; (2) the number assigned to the comment letter in the listing (with links) on ARB's website for this rulemaking of all written comments received in the rulemaking; and (3) the name of the person(s) signing the comment letter. These letters were received between April 10, 2012, and April 25, 2012.

Abbreviation	Commenter
SCPPA3	Lily Mitchell* and Norman A. Pedersen, Esq., attorney for the Southern California Public Power Authority Written Testimony: April 25, 2012
WSPA4	Catherine H. Reheis-Boyd, Western States Petroleum Association Written Testimony: April 25, 2012
SCE2	Nancy Chung Allred and Jennifer Tsao Shigekawa, attorneys for Southern California Edison Company Written Testimony: April 25, 2012
KORC3	Melinda L. Hicks, Kern Oil & Refining Company Written Testimony: April 25, 2012
SFPUC	Meg Meal, San Francisco Public Utilities Commission; Peter Brown, San Francisco Municipal Transportation Agency Written Testimony: April 25, 2012

The first 15-Day Notice was issued April 10, 2012, with an April 25, 2012, deadline. It solicited comment only on the limited number of additional regulatory modifications being made available. The regulatory modifications consisted of:

1. Changes to section 95481 (a) and (b) with added definitions and acronyms. The definition of "on-road," "electric vehicle (EV)," "battery electric vehicle (BEV)," "hybrid electric vehicle (HEV)," and "plug-in hybrid electric vehicle (PHEV)" were added, and acronyms "EV" and "HEV" were added to the list.

2. Changes to section 95484(a)(6) electricity regulated party provisions to provide a more accurate description of a fleet operator by including specifying any "person" operating a fleet, rather than any "company," and specify regulated parties for EV battery switch stations to allow a switch-station owner to opt in as a potential regulated party and receive credits.

3. Changes to section 95484(b)(3)(A) quarterly reporting requirements for imported petroleum intermediates, blendstocks, and finished fuel were deleted and added

a reporting requirement for marketable crude oil name (MCON) designation, volume (in gal), and Country (or State) of origin for each MCON supplied to the refinery during the quarter.

4. Changes to section 95484(b)(4) annual reporting requirements to include: MCON designation, volume (in gal), and Country (or State) of origin for each MCON supplied to the refinery during the annual compliance period.
    a. For each MCON, the constituent field names and the percentage of the MCON supplied from each field. For each MCON that includes a non-crude diluent, the type of diluent (e.g. natural gas condensate, naphtha, etc.) and the percentage of diluent in the MCON.
    b. For each field listed in 1.a.,the total annual volume produced by the field, the percentage produced using thermally enhanced oil recovery (TEOR), the percentage produced using oil sands mining, and the percentage that is upgraded to synthetic crude oil.

5. Changes to section 95485(a)(1) Table 4 Energy Densities of LCFS Fuels and Blendstocks to provide a more accurate value for ethanol. The energy density value for denatured ethanol was used to replace the original value shown for anhydrous ethanol because gasoline and similar fuels use denatured ethanol rather than anhydrous ethanol.

6. Changes to section 95486(f) to maintain the transparency and improve the Method 2A/2B certification process with a public comment period prior to the Executive Officer taking final action on certification applications.

7. Changes to section 95486(b)(1) Tables 6 and 7 to incorporate new and modified fuel pathways adopted as a result of the February 2011 Executive Officer hearing.

8. Changes to section 95486(b)(2)(A) to delete the requirement that “Crude oil used to produce CARBOB or diesel for which a credit is claimed in a calendar year pursuant to section 95486(b)(2)(A)3 will be included in the Annual Crude Average CI calculations for that year based on the CI of the crude oil prior to calculation of any innovative credits allowed pursuant to section 95486(b)(2)(A)3. Staff included language that specifies that the Annual Crude Average CI will be calculated using a three year rolling average of crude oil supplied to California refineries. The three-year rolling average will be phased in and will completely in place three years after the start of the new provisions.

9. Changes to section 95488(c)(3) to clarify the option for blind trading under the program. Staff specified that a credit facilitator may conduct a “blind transaction,” where the buyer’s and seller’s identifies are not disclosed to each other at the time of the transaction.

Despite the First 15-Day Change Notice's statement that "only comments relating to the modifications to the next of the regulation or to the additional documents and information referenced above shall be considered by the Executive Officer," several parties submitted comments on other topics not covered by the Notice.

Despite falling outside the scope of the notice, a number of comments nevertheless are summarized and responded to, as noted below. Although ARB legally is not required to summarize and respond to these comments under the APA, we provided a response to these comments because it was felt the general public and interested stakeholders could benefit from the additional clarity provided by the responses.

B. Electricity Regulated Party Provisions

IV-1. Comment: Minor revisions should be made to sections 95484(a)(6)(B), (C), (D) and (E) of the Proposed LCFS Regulation to include a requirement to notify an electrical distribution utility, as second-priority credit recipient, that it has become eligible to opt in as the regulated party and to remove the requirement for the Executive Officer to approve such opting in. (SCPPA3)

Response: This comment is not within the scope of the 15-day package changes. However, this comment was responded to as a 45-day comment (see comment C-38).

IV-2. Comment: Section 95484(c)(2) of the Proposed LCFS Regulation should be revised to remove the requirement for regulated parties to demonstrate the physical pathway of electricity from the fuel producer to the provider of the fuel to the end user in California. Such a demonstration may be relevant for other fuels, but it is not possible or useful in the case of electricity. (SCPPA3)

Response: This comment is not within the scope of the 15-day package changes. However, this comment was responded to as a 45-day comment (see comment C-61).

IV-3. Comment: The restriction to on-road vehicles in section 95484(a)(6)(E) should be revisited as soon as issues relating to credits for off-road vehicles are resolved. These changes will help to maximize the number of credits that are claimed and available for use by regulated parties and reduce the number of unclaimed credits. This is a priority of the ARB, as set out in the October, 2011 *Initial Statement of Reasons for Proposed Rulemaking* for the Proposed LCFS Regulation. (SCPPA3)

Response: This comment is not within the scope of the 15-day package changes. However, this comment was responded to as a 45-day comment (see comment C-45).

IV-4. Comment: ARB should revise the regulation language to clarify that section 95484 applies only to light-duty on-road vehicles until medium- and heavy-duty vehicles can be appropriately addressed through a robust stakeholder process. (SCE2)

Response: This comment is not within the scope of the 15-day package changes. However, this comment was responded to as a 45-day comment (see comment C-46).

C. Crude Oil Provisions

IV-5. Comment: WSPA also reiterates that it does not support any regulatory approach which differentiates crudes based on carbon intensity. (WSPA4)

Response: This comment is beyond the scope of the 1st 15-day revisions and therefore does not need a response. Please see comment B-15 for our response to a similar comment made during the 45-day comment period preceding the Board Hearing.

IV-6. Comment: ARB is proposing to adopt substantial and burdensome reporting requirements. The data which ARB proposes to require refiners to submit fall into three categories which are not mutually exclusive:

1. Data which are publicly available, and are therefore available to ARB without reporting by refiners.
2. Proprietary data, which may not be available to refiners in order for them to satisfy the reporting requirements.
3. Data which are variable or otherwise not precisely known.

Some of the data that would be required is publicly available, and ARB can obtain it without mandatory reporting by refiners. In fact, it appears that ARB may have access to several datasets that contain the information which can be purchased rather than requiring refiners to obtain the data for them.

Much of the data that ARB is requesting falls into the second category (proprietary data) that is considered commercially valuable trade secret information by the producers. Since the data is not available in the public literature, with much of it being crude producer proprietary data <u>not</u> necessarily available to the regulated parties (California refiners), it is unreasonable and unrealistic to require California refiners to submit this data. Refiners have no authority to compel the production and disclosure of proprietary information from crude producers around the world and cannot legitimately be penalized for the lack of voluntary disclosure of such proprietary information by third parties who are beyond ARB's jurisdiction. In particular, given that crude producers will now be aware of ARB's imposition of an obligation on the refiners to produce confidential or commercially sensitive information to ARB, it is foreseeable that the producers will be extremely reticent to provide any such information to regulated parties in the future. Further, refiners would be unable to verify that any information provided by third parties is complete or accurate.

Commercially sensitive information, such as trade secrets, and other confidential commercial information is routinely protected from unauthorized disclosure and dissemination. *See, e.g.*, *Stadish v. Sup.Ct. (So. Calif. Gas Co.)* (1999) 71 Cal. App.4th 1130, 1144–1145 (an owner of a trade secret has a privilege to refuse to disclose the secret, citing Evidence Code); Evidence Code § 1060 ("…the owner of a trade secret has a privilege to refuse to disclose the secret, and to prevent another from disclosing it….")[1]; Code of Civil Procedure § 2031.060(b)(5) (court may order that a "trade secret or other confidential research, development, or commercial information not be disclosed….". Nothing in AB 32 or elsewhere in the Health and Safety Code authorizes the inspection or copying of any writing or thing that is privileged or protected from disclosure by law or otherwise made confidential, or authorizes ARB to require that a regulated party obtain trade secret information from a third party for disclosure to ARB. Even assuming refiners were in possession of third party crude producer proprietary data, this data is confidential and/or likely protected from disclosure pursuant to written confidentiality agreements. Requiring disclosure of such information to ARB would subject refiners to potential contractual or other liability for disclosure of confidential and/or protected trade secret information. A rule which purports to require WSPA members to breach confidentiality obligations, or face imposition of penalties by ARB, is unlawful, arbitrary and capricious, and an abuse of discretion.

ARB's powers to obtain information are limited by law, to protect against oppression, undue burden or expense (i.e., compliance would be unreasonably difficult and expensive), among other burdens. *See* Code Civ. Proc. § 2031.060(b); Gov. Code §§ 11349.1(a)(4); 11349(d). The source of information here -- field level files and information maintained by third parties located around the world is not reasonably accessible to refiners located in California. Refiners may not lawfully be subjected to the extraordinary and unreasonable burden and expense that would result if they were forced to collect this information (even assuming it is not confidential or privileged). See Code Civ. Proc. § 2031.060(c). Refiners are under no obligation to create a compilation of any information that does not currently exist.

The unavailability of proprietary data has the potential to have a significant impact on the petroleum refining industry in California, since it could limit the population of crudes available to California refiners to those for which data are available. WSPA is very concerned about the potential marketplace distortions that ARB could create with such a policy. Even if data are available, many items may be variable or otherwise uncertain to the extent that only approximations are possible. By contrast, the proposed regulations would make refiners responsible for reporting actual data, not approximations. Even worse, some of these

[1] "Except as otherwise provided by statute, the provisions of this division apply in all proceedings. The provisions of any statute making rules of evidence inapplicable in particular proceedings, or limiting the applicability of rules of evidence in particular proceedings, do not make this division inapplicable to such proceedings." Evid. Code § 910; *see also* Gov. Code §§ 11349.1(a)(4); 11349(d) (regulations must be consistent meaning "in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or other provisions of law.").

approximations would have to be obtained from third (or even further removed) parties, making their verification by refiners difficult or impossible.

WSPA understands that data availability is a substantial concern in ARB's implementation and enforcement of the California Average system approved by the Board in December 2011. In fact, WSPA and the CEC have expressed this concern to staff throughout the Crude Screening Workgroup discussions as well as the December rulemaking. An ARB directive that refiners somehow produce such data is not a solution to the fundamental problem. The fact that much of the data that <u>are</u> available do not possess the necessary certainty to ensure regulatory compliance greatly compounds this disconnect. WSPA members cannot be required to report data to which we may not have access and cannot be held accountable for data of which we are not certain and cannot verify.

Specific examples of data uncertainty/complexity would be:

- Normal field maintenance would result in the percentage of crude from a given field for a MCON to vary from month-to-month,
- Commingling of crudes at loading ports would result in unknown field volumes to a vessel's cargo, and,
- Economics may result in a constant change in the diluent being used in a heavy crude oil during a quarter or reporting period.

WSPA believes that ARB's data needs would be better served by staff acquiring publicly available data outside of the regulations. ARB should also work with the CEC to explore potential data sources and to maximize the utility of those data that are available. Finally, WSPA strongly recommends that ARB more closely align the models to be used in the determination of the California Average and 2010 baseline with the data that are available. Moreover, it is mandatory that disclosure of electronically stored information, even if from a source that is reasonably accessible, be limited if it is possible to obtain the information from another more convenient, less burdensome or less expensive source. *Id*. § 2031.060(f). Thus, to the extent that some of the data sought by ARB is already publicly available, including several datasets available for purchase, ARB can and should obtain this information without mandatory reporting by refiners. Forcing California refiners to obtain this data for ARB represents an abuse of discretion since the refiners are in no better position than ARB to obtain this publicly available information.

The effect of staff's proposal would not only be to initiate reporting of crudes and volumes for crudes that are not imported, but also to extend the reporting requirement down to detailed information from the field level. The proposed amendments are overly broad and burdensome, and would subject refiners to an unreasonable risk of inadvertent noncompliance as framed.

For these reasons, WSPA recommends that the 15-day package annual reporting requirement revisions in Sections 95484(b)(4)(B)(2) and (3) regarding MCON and oil field data be deleted. The reporting requirement should be limited to Section 95484(b)(4)(B)(1) as follows:

"1. MCON designation, volume (in gal), and Country (or State) of origin for each MCON supplied to the refinery during the annual compliance period." (WSPA4)

IV-7. Comment: Kern has reviewed Resolution 11-39, as well as the referenced Attachment B containing staff's suggested modifications to the original proposal, and is particularly concerned with proposed changes to section 94584 (b) pertaining to reporting requirements. Specifically, paragraph 4 of 94584(b)(3)(A) and paragraphs 1-3 of 94584(b)(4)(B) require reporting of marketable crude oil names (MCONs), volumes supplied to a refinery, as well as other very detailed production information about each crude oil and generating oil field. As drafted, the modified LCFS text requires each producer of gasoline and diesel to report critical details about the production of crude oils such as the:

- particular field name;
- type and percentage of any diluent used;
- total volume of MCON produced within a given field;
- what percentage of that field's production involved enhanced oil recovery techniques or conversion to synthetic crude oil

These are details not likely to be known by a refiner and are key pieces of operational information, likely even considered confidential and/or commercially sensitive information, that oil producers and suppliers do not share with their customers. Likewise, such key details of types and volumes of crudes processed by each refiner is equally sensitive and confidential information, and should be treated as such. Kern respectfully requests that the language in the regulatory paragraphs cited above pertaining to reporting of crude oil production details be rejected. Oil producers are under no obligation to provide these details to their customers. Gasoline and diesel producers are being imposed an obligation to report data that is not readily available to them and furthermore is not readily obtainable. Understanding that certain data about crude oil lifecycle is requisite for determining carbon intensity of a given MCON, Kern is of the position that additional analysis of these matters is necessary for determining how best to gather such data. To place this requirement on the refiner is to set them up for noncompliance in meeting the LCFS reporting obligation. (KORC3)

Response: We disagree with the commenters' premise that the detailed information in the proposed regulatory language is, in all cases, necessarily unobtainable, unknowable, or sufficiently confidential such that it cannot be provided to ARB. For example, even if, arguendo, the crude oil producer considers the information to be proprietary and refuses to share the data with the oil refiners, we are not aware of any legal prohibitions against the oil refiners requiring the crude oil producers by contract to provide that information directly to the ARB as a condition of their crude oil purchase.

Nevertheless, this is a complex issue that warranted additional evaluation. Therefore, while ARB staff continues to work with stakeholders and sister agencies to determine how best to obtain the detail crude oil information, the reporting requirement for crude oil was modified, through subsequent 15-day changes in this rulemaking to the following:

- The marketable crude oil name (MCON) or other crude oil name designation, volume (in gal), and Country (or State) of origin for each crude oil supplied to the refinery during the annual compliance period.

IV-8. **Comment:** As previously expressed in public comments during the December 2011 rulemaking effort, and as further communicated in meetings with CARB staff, Kern is particularly interested in the accounting of crude oil carbon intensities and development of regulatory language supportive of an individual refinery approach to compliance with the industry baseline. This too was a key point made in Resolution 11-39 that warrants additional attention and analysis in order to be appropriately addressed. (KORC3)

Response: The commenter recommends shifting to a company-specific approach or allowing for some refiners to opt for company-specific accounting. Based on its review and consideration of various alternatives, including both hybrid and company-specific approaches, the Board adopted the California Average approach. The evaluation of alternatives is discussed on pages 81 to 84 of the ISOR. Although it adopted the California Average approach, the Board in Resolution 11-39 directed the Executive Officer to evaluate and propose (in a future rulemaking), as appropriate, an option for individual regulated parties to have their deficits for gasoline and diesel determined on a refinery-specific basis that accounts for the carbon intensity of domestic and imported crude oils, intermediate products, and finished fuels.

IV-9. **Comment:** Under the Administrative Procedure Act, any regulatory change proposed to be adopted using the 15-day notice and comment process must be "sufficiently related to the original text that the public was adequately placed on notice that the change could result from the originally proposed regulatory action." *See* Gov't. Code § 11346.8(c). In the current proposal, ARB has made very substantial, and very burdensome, changes to the annual reporting requirements that were previously adopted for section 95484(b)(4). These changes are impermissible because they are not "sufficiently related to the original text" that the public had adequate notice of this possible change.

The LCFS regulation originally required annual reporting of volume and "marketable crude oil name" (MCON) for all imported crude oil. ARB's changes to the annual reporting requirement proposed in October 2011 added reporting of crude oil produced in California using TEOR and non-TEOR methods. When the proposed changes came before the Board on December 11, 2011, ARB staff proposed various additional regulatory changes ("Attachment B"), none of which related to annual reporting of crude supplied to a refinery. Board Resolution 11-39, adopting the proposed changes, included direction to ARB staff to take specified additional actions, but made no mention of possible additional substantive changes to the reporting requirement. The current proposal would completely replace the reporting requirements adopted in December with an obligation to report not just the volumes and MCON of oil delivered to a refinery, but also the field names and detailed field-specific information. These changes bear no relation whatsoever to the original text of the LCFS regulatory changes proposed in October 2011, and therefore may not be adopted with only a 15-day notice and comment period. (WSPA4)

Response: See response to Comment IV-7 for the change in crude oil-related information to be reported. With regard to the APA comment, we disagree. Both the 45-day notice and the staff's proposed modifications that were considered by the Board at the December 2011 hearing clearly identified and described the baseline and annual average approach as being based on "production and transport of the crude oil used as petroleum feedstock for California refineries during the baseline calendar year" or "during a specified calendar year," respectively. It follows that information on MCON (or other marketing name) and volumes of each crude would be a necessity in conducting such calculations for baseline and annual average CI values. Thus, it is clear the modified provisions were "sufficiently related to the original text that the public was adequately placed on notice that the change could result from the originally proposed regulatory action."

IV-10. Comment: WSPA agrees with the proposed deletion of Section 95484(b)(3)(A)4 reporting requirements for imported petroleum intermediates, blendstocks, and finished fuel. This reporting requirement "category" also needs to be removed from "Table 3. Summary Checklist of Quarterly and Annual Reporting Requirements." (WSPA4)

Response: Table 3 was modified as suggested.

IV-11. Comment: The proposed provision that allows an LCFS credit facilitator/broker to conduct a "blind transaction" where the buyer's and seller's identities are not disclosed to each other at the time of the transaction may help protect confidential business information. However, this can make it harder to determine the legitimacy of purchased credits. ARB needs to build in safeguard provisions to ensure the validity of these LCFS credits. (WSPA4)

Response: We disagree. All credits and credit transactions under the LCFS program are required to meet the same standards, irrespective of whether the trades are conducted directly or "blindly" through a third-party facilitator. This means that all credits are required to be fully documented, as provided in the regulation, and all credit transfers, including those associated with blind transactions, will be processed through the ARB's system. For blind transactions, the credit facilitator will submit the credit transfer form to the Executive Officer (EO) with all the required information on the proposed credit transfer, including the identities of the seller and buyer. The EO will then process the proposed transfer and, if approved, will update the account balance of the seller and buyer to reflect the transfer. The transfer of credits will not be approved if the EO determines that one or more of the requirements for credit transfers has not been met (e.g., the seller's account has insufficient credits for the proposed transfer). A Credit Bank and Transfer System, currently under development, will facilitate secure online processing of credit transfers within LCFS Reporting Tool (LRT).

IV-12. Comment: Despite the Ninth Circuit Court of Appeal's decision on April 23, 2012 to stay the District Court's orders and judgments in the ongoing LCFS litigation[2], WSPA remains concerned that ARB released the current proposal during a period when the lower court's injunction against enforcement of the LCFS was in full force and effect. The United States District Court for the Eastern District of California determined that the LCFS violates the dormant Commerce Clause of the U.S. Constitution and enjoined enforcement of the LCFS regulation on December 29, 2011[3]. Under the terms of the injunction, ARB was barred from enforcing the LCFS during the pendency of the litigation. Although the injunction is no longer in effect, it should be noted for the record that ARB proposed to impose substantial new enforcement-related requirements on regulated parties during a time when the injunction was in effect and enforcement actions of all types were prohibited by court order. WSPA believes that the proposed LCFS modifications were impermissible under the explicit terms of the injunction if for no other reason than that ARB relied on its enforcement authority in Health & Safety Code sections 39600, 39601, 38510 and 38560 in proposing them (*see* ARB Resolution 11-39, December 16, 2011). The ARB's power to regulate under the Health and Safety Code is synonymous with its power to enforce. *See* Health & Safety Code §§ 39600, 39601, 38510 (bestowing upon ARB the power to regulate, and "to do such acts as may be necessary for the proper execution of the power and duties granted to" it); *see also* Webster's New Basic Dictionary (to regulate: "to direct or control in agreement with rules and laws"). The proposed modifications to the LCFS thus constituted an impermissible use of ARB's enforcement authority which violated both the terms and the spirit of the injunction. (WSPA4)

Response: We disagree. The preliminary injunction related to enforcement of the LCFS regulatory requirements during the time when the injunction was effective. We believe this rulemaking process is consistent with the court's injunction.

[2] (see "Order" (Document 54), *Rocky Mountain Farmers Union v. Goldstene*, No. 12-15131),
[3] . "Order on RMFU Plaintiffs' Preliminary Injunction Motion" (Document 259), *Rocky Mountain Farmers Union v. Goldstene*, No. CV-F-09-02234 LJO DLB, E.D. Cal., December 29, 2011.

V. SUMMARY OF COMMENTS MADE DURING THE SECOND 15-DAY COMMENT PERIOD AND RESPONSES

A. List of Commenters

The table below identifies the two comments received during the second 15-day comment period. It provides a correlation between (1) the abbreviation used in this Section V to refer to a comment letter; (2) the number assigned to the comment letter in the listing (with links) on ARB's website for this rulemaking of all written comments received in the rulemaking; and (3) the name of the person(s) signing the comment letter. These letters were received between August 9, 2012, and August 24, 2012.

Abbreviation	Commenter
KORC4	Melinda L. Hicks, Kern Oil & Refining Company Written Testimony: August 24, 2012
WSPA5	Catherine H. Reheis-Boyd, Western States Petroleum Association Written Testimony: August 24, 2012

The Second 15-Day Notice was issued August 9, 2012 with an August 24, 2012 deadline. It solicited comment only on the limited number of additional regulatory modifications being made available. The regulatory modifications consisted of:

1. Changes to section 95481 to the definitions of "producer" and "production facility" to further clarify who would be considered an out-of-state producer by specifying that one must opt into the program under section 95480.3 in order to be considered an out-of-state producer.

2. Changes to section 95484(b)(4)(B) with deletions of certain field-specific reporting requirements for producers of CARBOB, gasoline, or diesel fuel.

3. Changes to section 95486(b)(1) to clarify that the Executive Officer may approve the use of a model other than CA-GREET to generate carbon intensity value, if the Executive Officer determines the model is equivalent to CA-GREET, version 1.8b.

4. Changes to section 95486(c) Modified Method 1 (Method 2A) provisions to clarify that the Executive Officer may approve the use of a model other than CA-GREET to generate carbon intensity value, if the Executive Officer determines the other model is equivalent to CA-GREET, version 1.8b.

5. Changes to section 95486(d) to clarify that the Executive Officer may approve the use of a model other than CA-GREET to generate carbon intensity value, if the Executive Officer determines the other model is equivalent to CA-GREET, version 1.8b.

6. Changes to section 95486(f)(3)(C) pathway application requirements to clarify that when preparing the life cycle analysis of a proposed fuel pathway, applicants must use CA-GREET or a method approved by the Executive Officer as equivalent to CA-GREET.

Despite the Second 15-Day Change Notice's statement that "only comments relating to the modifications to the next of the regulation or to the additional documents and information referenced above shall be considered by the Executive Officer," several parties submitted comments on other topics not covered by the Notice.

Despite falling outside the scope of the notice, a number of comments nevertheless are summarized and responded to, as noted below. Although ARB legally is not required to summarize and respond to these comments under the APA, we provided a response to these comments because it was felt the general public and interested stakeholders could benefit from the additional clarity provided by the responses.

B. Crude Oil Provisions

V-1. **Comment:** Absent from the modified LCFS provisions are options coupled with or in lieu of the California Average Refinery Approach to account for HCICO that would provide a fair means of accounting for deficits incurred as a result of processing HCICO. An approach must be incorporated that provides equal treatment to all refiners and which does not unjustly distribute deficits across the industry—penalizing one refiner for another refiner's choices.

Although Staff originally expressed their intention to recommend the hybrid California average/company specific approach to the Board, ultimately Staff proposed the California Average Refinery Approach. (See the *2011 Low Carbon Fuel Standard 2011 Program Review Report,* section 9, paragraph E.) However, as acknowledged by CARB Board Member De La Torre during the December 16, 2011, hearing, not only could facilities benefit from being measured on their own performance as opposed to a potentially unrelated "industry average" performance, the "industry average" approach also threatens to penalize clean facilities that get lumped in with the "average" mix. Indeed, Resolution 11-39 specifically directs the Executive Officer to evaluate and propose an option for individual regulated parties to have their deficits determined on a refinery-specific basis, which these modifications fail to address.

Kern has actively pursued a solution to the "average refinery" issue throughout the rulemaking process, for example: providing comments in advance of and public testimony at the December 16, 2011, hearing; meeting with CARB Staff in February 2012 regarding alternatives for individual facility compliance determinations, the flaws inherent to the California Average Refinery approach and the detriment it would have to Kern by having to subsidize other refiners' when the industry exceeds the baseline; and providing April 25, 2012, comments to the First Notice of Modified Text. Kern's specific concerns regarding the

California Average Refinery approach to compliance with the Industry Baseline are as follows:

1. The Cross-Subsidization by Spreading Deficits Industry-Wide Creates an Incentive to Run Higher CI Crude Oils.
2. Low-Volume Refiners Have a Severely Limited Ability to Impact the Industry Average.
3. Infrastructure Flexibilities, or the Lack Thereof, Affect Refiners' Ability to Run HCICO and Widen the Refiner Disparity Across the Industry Average.
4. The Average Refinery Approach Makes Compliance Forecasting and Budgeting Nearly Impossible.
5. The Industry Average Could Result in Significant Costs to Refineries Regardless of Whether an Individual Refinery Stayed Below the Baseline.

Immediate action must be taken to enact provisions for individual compliance determinations or a hybrid equivalent to address the disparities in the current regulations for low-volume refineries. CARB should adopt an individual compliance approach under which all refineries would stand on their own merit in comparison to the industry baseline, eliminating the risk of cross subsidization and the incentive for complex refineries to utilize HCICO.

In lieu of an individual compliance alternative, certain exemptions could be added to the current approach to protect the uniquely disadvantaged low-volume, low-energy-use and/or low complexity refiners. Such exemptions could include any combination of the following criteria:

- Non-HCICO demonstration exemption: Provide an exemption to refiners that can demonstrate that no crude oil processed during the compliance year exceeded the established baseline CI.
- Low-volume processor exemption: Provide an exemption to refiners processing less than 5% of California's total crude capacity from any deficits that would otherwise be incurred by an industry average CI in excess of the established baseline because small processors have limited ability to affect the average CI, but conversely are easily affected by larger refiners' decisions to process HCICO.
- Low-volume producer exemption: Provide an exemption to refiners producing less than 5% of California's total primary refined products from any deficits that would otherwise be incurred by an industry average CI in excess of the established baseline. (KORC4)

Response: This comment falls outside the scope of the Second 15-Day Change Notice and therefore requires no further response.

V-2. **Comment:** Draft modifications proposed in April 2012 included onerous reporting requirements for production-specific information about individual crude oils processed by refiners each quarter. The current modifications being proposed have since eliminated this additional reporting requirement in lieu of simply reporting the name, volume and origin of each crude oil processed. Kern wishes to express its appreciation for CARB's consideration of points made and elimination of the requirement for detailed crude oil production data. (KORC4)

Response: We acknowledge appreciation by Kern Oil on the issue of updated crude oil production reporting requirements.

V-3. **Comment:** The current rulemaking incorporates 2009 as the baseline year for CA-Average Crude CI, which is the benchmark for compliance determination within the California Average Refinery Approach with respect to accounting for HCICO. Attachment B to Resolution 11-39 states that the current revisions were intended to incorporate the most recent data representing 2010. At the time of the December 2011 hearing, 2009 was proposed as the revised baseline (in lieu of the original 2006); however, it was also noted in Attachment B that sufficient data should be available in 2012, and it was in fact Staff's intent, to further update the baseline to 2010.

In February 2012, staff confirmed to Kern that sufficient data was available to use 2010 as the baseline. CARB surveyed California refineries in August 2011 for crude oil source and volume data covering operations from 2006 through 2010, assumedly for this purpose. Additionally, staff presented materials in a July 2012 workshop that revealed a draft 2010 baseline crude CI of 12.5 gCO2e/MJ and called attention to updating to a 2010 baseline as part of the next 15-day change.

CARB should amend the current revisions to include 2010 as the baseline year. Doing so provides the appropriate consideration of factors that can impact the baseline year—for example, changes and fluctuations in sources of crude available to California refineries, changes in market conditions that may have altered business decisions from one year to the next, and political effects on crude market and importations. Kern agrees that this set of modifications are intended to make the rule as up to date as possible, which should include the most recent baseline year. (KORC4)

Response: While this comment falls outside the scope of the Second 15-Day Change Notice, we should note that the amendments as adopted do incorporate the suggested change to a 2010 baseline.

V-4. **Comment:** The current modifications propose to add language to Section 94586 related to determination of CIs and the approved models for doing so. While the modified text does not specify a particular model, it is Kern's understanding from public workshops hosted by Staff in March and July 2012, that Staff is seeking approval to use the recently developed OPGEE model. Use of this OPGEE model, as developed by Stanford University for CARB, would give Staff and those seeking specific new pathway approvals an alternative to the CA-GREET model for determining crude oil CIs. While Kern has no specific technical objection to the OPGEE model at this time, there are generally many concerns and unanswered questions surrounding the use of the model:

- The model is still in infancy stages, having just been developed in 2012; the beta version was introduced in March 2012, with updates made and the next version released in June.
- The model has been built on a number of assumptions because many of the data inputs necessary are not publicly available information.
- There has been no opportunity to prove or ground-truth the model for accuracy. Without specific field operating data to input, developers have not been able to compare outputs using assumptions to outputs using known data. Without this opportunity, how can anyone be sure the results are reliable?
- There has been no information made available to compare CIs of crude oils established using the CA-GREET model to CIs of the same crude oil established with OPGEE. What makes OPGEE more accurate, warranting that it replace CA-GREET for the crude oil production and transport CI value?
- If the CIs of fuels in the regulations have been determined solely using CA-GREET, then are we even comparing apples to apples by having new CIs for crude oil baseline/annual compliance and new fuel pathways established based on a separate or possibly multiple model outputs?

CARB should consider and respond to the above comments, and provide additional supporting documentation justifying the use of and substantiating output results from the OPGEE model. (KORC4)

Response: The CA-GREET model uses a simplified method to calculate carbon intensity of crude. The only inputs to the CA-GREET model are the crude recovery efficiency and fuel shares for crude oil production. In applying this model ARB staff assumed model input values for each of the different crude slates to calculate a weighted average carbon intensity. To refine this approach, staff tasked Stanford University researchers to develop a tool that uses process parameters (steam-to-oil ratio, reservoir depth, etc.), crude origins, and other applicable metrics to calculate carbon intensities of individual crudes. The researchers conducted extensive searches to obtain information relevant to appropriate calculation methodologies and inputs required for the model. In areas where data has been limited, they have used best engineering judgments to estimate default inputs to the model. The methodology and inputs used in the OPGEE model are described in detail in both the model and the accompanying documentation.

Staff has and will continue the process of “ground-truthing” the model utilizing data for various crude slates as data sources are identified. In fact, utilizing inputs for Alaskan North Slope oil fields, the model predictions for associated gas consumption for lease operations are within 5 percent of the value reported by field operators to Alaska Oil and Gas Conservation Commission.

As for comparison to CA-GREET, the OPGEE is a much more sophisticated approach to estimating carbon intensity. It does not use a generic average approach for a whole region (or regions) but rather uses much more detailed inputs to calculate carbon intensity for crude recovery and transport. Similar to the process of adding land use change carbon intensity (using the GTAP model) for biofuels, the output from the OPGEE model will replace the crude production plus transport components of the Well-To-Wheel analysis from CA-GREET and retain all the other components of the pathway analysis from the CA-GREET model.

V-5. **Comment:** Introductory text in the Second Notice of Modified Regulatory Text referenced additional anticipated modifications to the LCFS:

> Although this Second Notice of Modified Regulatory Text ("Second I5-Day Change Notice") specifies proposed modifications related to the crude oil provisions, **staff intends to propose additional modifications related to the crude oil provisions in a subsequent notice of modified regulatory text.** Accordingly, it remains [C]ARB's intent to develop additional calculation methodologies, accounting procedures, and other measures to further refine the provisions that address the CI of petroleum crude oils, blendstocks, intermediates, and finished products refined in California or imported into the State. Staff intends to **bifurcate adoption of the regulatory amendments** presented at the December 2011 Board hearing. Therefore, the approved amendments to the regulation, except for modifications to the crude oil provisions and updates to the 2010 baseline crude carbon intensities, will enter into force as expeditiously as possible. (Emphasis in original letter.)

Kern would like clarification on CARB's statement on:

- What additional proposed modifications related to crude oil provisions does staff intend to make?
- When would such modifications be proposed?
- What additional calculation methodologies, accounting procedures, and other HCICO provisions are to be proposed or further refined?

This bifurcated approach related to the crude oil provisions is a significant defect in the rulemaking process. Stakeholders cannot accurately assess the modifications and potential cumulative impacts if CARB continues to piecemeal the rulemakings. Assessing compliance strategies, determining compliance costs, business impact, etc. are impossible when significant anticipated amendments remain in limbo with no particular resolution in sight.

Staff has been tasked with evaluating changes, has presented anticipated solutions and/or timings in meetings and workshops, and yet has then repeatedly delayed finalization without explanation and to the detriment of the impacted stakeholders. Prime examples are the low-energy-use refiner provisions, provisions for Individual Refinery compliance option within the CA-Average Refinery Approach to HCICO, and using 2010 as the baseline year, all discussed above. As a result, Kern's projections for compliance with LCFS, taking into account the numerous pending modifications and provisions being considered, span an eleven year period in which we may or may not incur a deficit obligation, which may range anywhere from $500,000 to over $4 million annually. No business can appropriately plan for that.

CARB should stop "bifurcating" these rulemakings so impacted facilities can consider all the intended changes at once, in total. At a minimum, CARB should provide clearer information at this time on anticipated additional modifications and the timing of their proposal and effectuation. (KORC4)

Response: The additional modifications related to crude oil provisions were released as part of the Third Notice of Modified Regulatory Text. These modifications included using 2010 as the baseline year. And the proposed bifurcation noted by the commenter ultimately was not conducted by ARB; a single package covering this rulemaking was submitted to the Office of Administrative Law.

As noted in response to Comment B-6, the Executive Officer has been directed by the Board to evaluate and propose, as appropriate as part of a future rulemaking, an option for individual regulated parties to have their deficits for gasoline and diesel determined on a refinery-specific basis that accounts for the carbon intensity of domestic and imported crude oils, intermediate products, and finished fuels. This evaluation will commence after the current rulemaking is finalized.

C. Low Energy Use Refineries

V-6. Comment: Also absent from the current modifications are provisions addressing the inequalities and disadvantages inherent under the average refinery assumptions in the regulation and determination of CIs for finished fuels to low-energy-use, low-complexity refiners. In reality, the inherent differences in less-complex, less energy-intensive refineries as compared to large, sophisticated refineries, which employ many additional processing technologies, impact the appropriate CI value to be assigned to the finished products of those respective refineries. The CIs assigned to gasoline and diesel in the Lookup Tables, however, are modeled from an "average refinery," and therefore are not representative of the actual CIs of fuels produced at low-energy-use, low-complexity refineries, like Kern.

The need for and technical basis behind such provisions has been affirmed by CARB staff at numerous junctures over the years, but continues to get passed over. On November 18, 2010, Board Resolution 10-49 directed Staff to explore low-energy-use refiner provisions addressing the concerns expressed by Kern and others. At the July 22, 2011, workshop, Staff acknowledged receipt of proposed low-energy-use refiner provisions and ongoing efforts to develop alternatives. At the September 14, 2011, Public Workshop, Staff's presentation and verbal remarks noted that the low-energy-use refiner provisions were in review. Staff represented to Kern in a September 29, 2011, telephone call that low-energy-use refiner provisions were to be included in the summer 2012 amendments, and to be in effect by January 1, 2013. Staff again presented on the low-energy-use refiner provisions but noted their deferral to 2012 at the October 14, 2011, Public Workshop. Staff reiterated to Kern on November 4, 2011, that the low-energy use refiner approach would be added in 2012 and in effect for 2013. At the December 16, 2011, Board Hearing, Staff s presentation to the Board contained a slide referencing continued work exploring low-energy-use refiner provisions. However, on February 22, 2012, Staff informed Kern that addition of the low-energy-use refiner provisions had shifted to either fourth quarter 2012 or early 2013, pushing the effective date to at least 2014. To date, the low-energy-use refiner provisions still have yet to be addressed.

Kern emphasizes the following points regarding the low-energy-use refiner provisions:

1. <u>Kern has worked closely with CARB Staff to Develop a Solution to the CARB Acknowledged Significant CI Disadvantage for Low-Energy Use Refiners.</u>

As set forth above, since early in this rulemaking, Kern has been working with CARB staff to find a solution to this significant CI disadvantage. Kern, with the help of CARB staff, has focused on providing a technically sound, transparent approach to this issue. Throughout 2009, Kern met with CARB Board members and elected offices regarding the potential issues with LCFS as then-proposed. In 2010, Kern met with CARB Staff on several occasions, including a meeting with Chairwoman Mary Nichols, to explore and substantiate proposed alterative provisions to address the low-energy-use refiner inequalities in the LCFS. In April 2011, Kern met with Staff and presented a proposal for modified regulatory text, with substantial data forming the foundation for the suggested provisions. This approach was discussed with CARB staff, CARB Board Members, Legislators, and the Governor's office, and was well-understood, received and accepted. Initially, Kern was encouraged that data showing a low-energy-use refiner CI of 5 gCO_2e/MJ less than the "average refinery" would provide a useful context to developing a "significance" threshold between refineries. This fact seems to be a cornerstone within the LCFS regulation, and is consistent with the same CI reduction required to be demonstrated by other industries seeking CARB's approval for new fuel pathways.

2. The Current CI Unfairly Subsidizes Higher Than Average Energy-Use Refiners

For each facility in California that is lower than the "average refinery," there is a refinery that is equally higher than the average. The Current LCFS regulations require low-energy use refiners, like Kern, to subsidize higher than average refiners' obligations. By Kern's calculations, Kern would be subsidizing higher-energy-use refiners with the net equivalent of 40 years of Kern's obligations. This is clearly a disproportionate disadvantage for low-energy-use refiners.

3. A 5 gCO_2e/MJ Low-Energy-Use Refiner Credit Would Result in Justifiable Relief of Eight Years to a Refinery like Kern.

CARB Staff confirmed to Kern in June 2011 its agreement with Kern's technical basis for a low-energy-use refiner credit, and that it was CARB's intent to include such a provision in the December 2011 regulation revision. At that time, CARB preferred to look at an alternative and arbitrary approach with a much shorter "head start" for low-energy-use refiners. Kern's proposal was set aside on Staff's erroneous assertion that a 5 gCO_2e/MJ low-energy-use refiner credit would result in Kern not having to purchase carbon credits until about the year 2050, which seemed unreasonable to Staff. Alternatively, Staff proposed that seven to eight years of relief would be appropriate. However, no technical justification was provided to Kern to substantiate this "2050" assertion and Kern's subsequent calculations have determined that this projection is grossly exaggerated.

Kern has evaluated scenarios of compliance obligations over the course of the next ten plus years using the proposed low-energy-use refiner provision of a 5 gCO_2e/MJ credit. It is unclear to Kern where Staff came up with their projection of Kern not incurring an obligation until 2050; our data demonstrates that a 5 gCO_2e/MJ credit would provide the justifiable relief of approximately 8 years, up to 2026. This clearly fits within the seven to eight year range of relief that Staff agreed to and acknowledged was appropriate.

RECOMMENDATIONS:

CARB should reinvest resources in addressing a set of provisions for low-energy-use refiners and do so without further delay. CARB should adopt the 5 gCO_2e/MJ credit proposed by Kern. The technical approach taken by Kern with regard to the low-energy-use refiner credit provision is one that CARB had asked us to utilize. Kern has been in routine communications regarding the activities and specific data that would be considered. Kern used publicly available data directly compared to CI as calculated with the CA-GREET model. Kern was transparent and conservative in utilizing data to develop this provision and it should be adopted by CARB. In the alternative, the magnitude of the low-energy-use refiner provision is irrelevant if the goal is to use a defensible scientific approach and to not pick winners and losers. However, CARB needs to address the significant disparity in the currently assigned CIs for finished products. (KORC4)

Response: This comment is outside the scope of the Second 15-day Notice. See also response to Comment G-15 for a discussion of the low-energy use refinery provision.

VI. SUMMARY OF COMMENTS MADE DURING THE THIRD 15-DAY COMMENT PERIOD AND RESPONSES

A. List of Commenters

The table below identifies the six comments received during the third 15-day comment period. It provides a correlation between (1) the abbreviation used in this Section V to refer to a comment letter; (2) the number assigned to the comment letter in the listing (with links) on ARB's website for this rulemaking of all written comments received in the rulemaking; and (3) the name of the person(s) signing the comment letter. These letters were received between September 17, 2012, and October 2, 2012.

Abbreviation	Commenter
WSPA6	Catherine H. Reheis-Boyd, Western States Petroleum Association Written Testimony: October 1, 2012
SHELL2	Robert E. Nelson, SHELL Written Testimony: October 1, 2012
BP3	Ralph J. Moran, BP America, Inc. Written Testimony: October 2, 2012
RPMG	Jessica Wiechman, RPMG Written Testimony: October 2, 2012
GP	John O'Donnell, GlassPoint Solar, Inc. Written Testimony: October 2, 2012
KORC5	Melinda Hicks, Kern Oil and Refining Company Written Testimony: October 2, 2012

The Third 15-Day Notice was issued September 17, 2012, with an October 2, 2012, deadline. It solicited comment only on the limited number of additional regulatory modifications being made available. The following is a summary of the proposed substantive modifications to the regulation and staff's rationale for making them. All references to sections refer to title 17, CCR, unless otherwise noted. The following list does not include modifications to correct typographical and citation errors, numbering errors, grammar errors, or the rearranging of sections and paragraphs for structural improvements, nor does it include minor revisions made to improve clarity or other nonsubstantive modifications.

1. Changes to section 95480.3 to clarify the information required to be submitted to ARB in order to opt-in to the LCFS program, the process for a party that opts-in to the LCFS program to select a carbon intensity value, and that the LCFS

recordkeeping requirements applicable to regulated parties will apply to parties that opt-in to the LCFS.

2. Changes to section 95480.5 related to jurisdiction. Staff added any submittal of documentation pursuant to the crude oil innovative method provision to actions that establish a person's consent to be subject to the jurisdiction of the State.

3. Changes to section 95481 to add a definition for "day" to mean calendar day unless otherwise specified.

4. Changes to definitions of "Aggregation Indicator," "Biofuel Production Facility," "Business Partner," "Physical Pathway Code," "Production Facility," "Transaction Date," "Transaction Quantity," "Transaction Type" in section 95481(a)(1), (8), (15), (47), (51), (56), (57), (58), respectively, to remove reference to the LRT.

5. Changes to the definition of "On Road," in section 95481(a)(45), for clarity.

6. Changes to section 95481(a)(40) to clarify definition of reporting deadlines. Staff clarified the definition of "LRT Reporting Deadlines" by referencing the quarterly and annual reporting dates specified in section 95484(b)(1).

7. Changes to section 95482(b) and (c) to revise the compliance schedules. Staff revised the LCFS compliance schedules with updated average carbon intensity requirements for gasoline and diesel fuel. The average carbon intensity requirements for years 2013 to 2020 reflect reductions from revised base year 2010 carbon intensity values for California reformulated gasoline (CaRFG) and ultralow-sulfur diesel (ULSD).

8. Changes to section 95484(b)(3)(A)4 to revise reporting requirements. Staff revised the quarterly and annual reporting requirements to accommodate situations when crude is supplied to a refinery without a Marketable Crude Oil Name (MCON). Slight revisions were made to further clarify what producers of California reformulated gasoline blendstock for oxygenate blending (CARBOB), gasoline, or diesel must report for each of its refineries.

9. Changes to section 95486 revising Table 3. Staff revised the *Summary Checklist of Quarterly and Annual Report Requirements* (Table 3) to be consistent with revisions made to the reporting requirement for gasoline and diesel.

10. Modifications to section 95486(a)(4) to clarify when a carbon intensity value is defined as "unable to be determined."

11. Changes to section 95486 to incorporate the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model (version 1.0). Staff added the model information to clarify the specific model, or equivalent model, to be used for the generation of carbon intensity values for crude oil production and transport to

California refineries. The OPGEE model version 1.0 is incorporated in the regulation by reference.

12. Changes to section 95486(b)(1) to update fuel pathway supplements. Staff updated the fuel pathway supplements for CARBOB, CaRFG, and ULSD (supplement version 2.0, dated September 12, 2012).

13. Changes to section 95486(b)(1) to add crude carbon intensity values to a new table. Staff added individual crude carbon intensity values in separate Table 8, and revised Tables 6 and 7 Carbon Intensity Lookup Tables for gasoline, diesel and their substitutes with updated 2010 CARBOB, ULSD, and baseline crude average carbon intensity values for each fuel.

14. Changes to section 95486(b)(2)(A)1 updating the baseline carbon intensity values to a 2010 baseline. Staff updated CARBOB, ULSD, and Baseline Crude Average carbon intensity values to reflect a 2010 Baseline. The 2009 baseline calendar year referenced in CARBOB and diesel fuel deficit calculations were updated to 2010.

15. Changes to section 95486(b)(2)(A) to include an application process for innovative crude production methods. Staff proposed modifications to specify the process for a crude oil producer to apply for approval of innovative crude production methods. A regulated party or oil producer would need to obtain approval of the innovative crude oil production method before a regulated party can receive credit under the LCFS regulation for use of that crude oil production method.

16. Changes to section 95486(f)(3)(C) to clarify Method 2A/2B pathway application requirements. Staff proposed language to clarify the information that would be required to be submitted in the Method 2A/2B application form and made modifications to other application requirements, including format for citations and references.

17. Changes to section 95486(f)(3)(D) to specify when a Method 2A/2B application is determined to be complete. Staff proposed revisions to clarify the process that will be used to determine if a Method 2A/2B application is complete and the process for a party to submit additional information, if needed.

18. Changes to section 95486(f)(3)(E) to clarify public comment procedures for Method 2A/2B. Staff proposed modifications to specify the process for submission of public comments on Method 2A/2B applications and the applicant's opportunity to respond to any public comments on Method 2A/2B applications.

19. Changes to Section 95486(f)(3)(F) to specify date on which Method 2A/2B evaluation would begin. Staff proposed modifications to clarify the time period for evaluation of a Method 2A/2B application, including the date on which evaluation would begin.

20. Changes to section 95486(f)(3)(H) to specify that Method 2A/2B applications that are denied without prejudice may be resubmitted.

21. Changes to section 95486(f)(3)(I) clarifying evaluation criteria for Method 2A/2B applications. Staff proposed amendments to clarify the criteria against which Method 2A/2B applications would be evaluated.

22. Changes to section 95486(f)(3)(L) to specify the recordkeeping requirements for approved Method 2A/2B applications, including that records required to be retained must be submitted to the Executive Officer within 20 days of a written request.

Despite the Third 15-Day Change Notice's statement that "only comments relating to the modifications to the next of the regulation or to the additional documents and information referenced above shall be considered by the Executive Officer," several parties submitted comments on other topics not covered by the Notice.

Despite falling outside the scope of the notice, a number of comments nevertheless are summarized and responded to, as noted below. Although ARB legally is not required to summarize and respond to these comments under the APA, we provided a response to these comments because it was felt the general public and interested stakeholders could benefit from the additional clarity provided by the responses.

B. Crude Oil Provisions

VI-1. Comment: <u>Page 19 - Section 95482</u>. Average Carbon Intensity Requirements for Gasoline and Diesel, and Page 62 Table 6. Carbon Intensity Lookup Table for Gasoline and Fuels that Substitute for Gasoline

In updating the LCFS baseline for gasoline to 2010, staff only completed one portion of the revisions—the updated baseline to reflect changes in the estimates for the CI of CARBOB based on new information on crude oil—but staff failed to update the CI of ethanol based on new information. Because the CARBOB 2010 baseline value was updated, the ethanol value should be as well.

ARB is continuing to use an ethanol CI value of 95.66 as documented in the following document Detailed California-Modified GREET Pathway for California Reformulated Gasoline (CaRFG) http://www.arb.ca.gov/regact/2011/lcfs2011/carfg.pdf which is part of the 15-day package. This value is the same as what was used for the 2006 baseline and included a disproportionate amount of ethanol assumed to be from California with a lower CI. ARB assumed ethanol consisted of "80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG". According to the CEC's IEPR document "California ethanol facilities contributed less than 4 percent of the state's needs in 2010" (IEPR page 183). The lower, inaccurate CI value used by CARB impacts the CaRFG 2010 baseline value used in setting the annual compliance targets in Section 95482(b).

In addition, the CI values for Midwestern corn ethanol should have been updated based on data presented to CARB since the original rulemaking: specifically, many of the large number of “new” pathways approved by CARB via Method 2A actually reflect existing industry practices employed in 2010 that were not represented in the original calculations.

This exercise should be simple since the LCFS was in effect for reporting in 2010 and therefore, ARB can calculate the average ethanol CI for 2010. Once this calculation is made, the CaRFG baseline value and compliance target table should be updated accordingly. ("Detailed California-Modified GREET Pathway for California Reformulated Gasoline (CaRFG)" and Section 95482(b) page 19). (WSPA6)

Response: We agree with much of this comment and will evaluate an update of the ethanol CI value used in calculating the compliance schedule targets for gasoline and its substitutes as part of formal rulemaking in 2013. We did not update the ethanol CI from 2006 to 2010 during this rulemaking for several reasons. First, the year 2010 was a voluntary compliance year, so we do not have a complete picture of the sources of ethanol blended with CARBOB in California during 2010. To obtain this information we will issue a survey to California refiners and blenders. This survey will allow us to determine volumes and actual CI values for ethanol used in California during 2010. Second, we need to evaluate the effect that the increase in CI for gasoline and diesel (as determined in this rulemaking) has on the CI values for ethanol and incorporate this effect into the ethanol CI values if it is deemed significant. Third, we intend to update the LUC CI value for ethanol as part of a formal rulemaking in 2013. Because the change to the ethanol LUC value also affects the compliance targets for gasoline, we decided to make all changes associated with ethanol CI values as part of the same rulemaking.

VI-2. Comment: The LCFS requires a 10% reduction—from a 2010 baseline year through 2020—in the carbon intensity of both gasoline and diesel. The carbon intensity for gasoline is a combination of the carbon intensity for the fuel from the refinery (CARBOB) and the ethanol added at the terminals.

The LCFS was first adopted in 2009. CARB used estimates of what the carbon intensity for ethanol and CARBOB would be in 2010 to project the baseline. In the latest 15-day package of rule amendments, CARB has updated the carbon intensity for CARBOB based on 2010 data along with the annual compliance targets, but has not done so for ethanol.

The original ethanol projections assumed a much larger supply of lower carbon intensity ethanol from California which has not materialized. The original estimate assumed 20% of lower CI ethanol from California, but according to the CEC’s 2011 IEPR, the actual amount of lower CI California ethanol was only 4% (see page 146). Assuming ethanol with inaccurate lower carbon intensity in the baseline results in more aggressive annual reduction targets than the regulation requires. CARB should utilize scientifically-based, accurate data.

For BP alone, CARB's current proposal to not update the CI value for ethanol results in additional costs in the 10s of millions of dollars between 2013 and 2015 alone. CARB's proposal also requires BP and other refiners to find and import more even larger volumes of scarce advanced biofuels like sugar cane ethanol and renewable diesel. This makes an already challenging standard even more difficult and costly than necessary.

BP requests that CARB use available data for actual ethanol blended into fuel in California during the year 2010 to establish an accurate baseline for gasoline and adjust the compliance target accordingly in Tables 1 and 2 of Section 95482. CARB has this data via the reporting requirements in the LCFS or from the CEC. (BP3)

Response: We agree with much of this comment and will evaluate an update of the ethanol CI value used in calculating the compliance schedule targets for gasoline and its substitutes as part of formal rulemaking in 2013. We did not update the ethanol CI from 2006 to 2010 during this rulemaking for several reasons. First, the year 2010 was a voluntary compliance year so we do not have a complete picture of the sources of ethanol blended with CARBOB in California during 2010. To obtain this information we will issue a survey to California refiners and blenders. This survey will allow us to determine volumes and actual CI values for ethanol used in California during 2010. Second, we need to evaluate the effect that the increase in CI for gasoline and diesel (as determined in this rulemaking) has on the CI values for ethanol and incorporate this effect into the ethanol CI values if it is deemed significant. Third, we intend to update the LUC CI value for corn and Brazilian sugarcane ethanol as part of a formal rulemaking in 2013. Because potential changes to these ethanol LUC values may affect the compliance targets for gasoline, we think it preferable to make all changes associated with 2010 baseline ethanol CI values as part of the same rulemaking.

BP's claim that not updating the ethanol CI value as part of this rulemaking will cost tens of millions of dollars is unsupported. Although BP is correct in noting that less ethanol produced in California during 2010 will tend to increase the California Average Ethanol CI, using actual 2010 CI values for Midwest ethanol facilities, which, through the Method 2A/2B process, have been shown to be lower than originally estimated, will tend to lower the California Average Ethanol CI value. Because we do not know whether the California Average Ethanol CI value during 2010 will be greater than or less than the 2006 estimate, the impact on compliance costs cannot be determined at this time.

VI-3. Comment: Page 58 - (a)(5)(B) - The default CI for biodiesel was deleted in the text but a replacement value was not substituted. (WSPA6)

Response: This value was purposefully deleted and is not necessary. The regulation language now refers to the carbon intensity value for ULSD given in Table 7.

VI-4. Comment: Page 71 – Table 8 – Carbon Intensity Lookup Table for Crude Oil Production and Transport.

- The crude CI values for 2010 are not the same as the crude CIs issued for review in July. Can ARB explain these differences?
- Table 8 (cont.) - The volumes used to assess the baseline crude average are not shown in Table 8. Are they the same as was issued in the July data? In the future, will the volumes be disclosed annually when the crude CI is estimated?
- Crudes for all countries other than the United States have CI values listed in the regulations via this table, the significance of which is that changes to those values require a rulemaking. Despite the diversity of crudes produced in California, this state is represented by an average rather than values for the individual crude. This constitutes unequal treatment for California crudes vs. non-California crudes. (WSPA6)

Response: The crude CI values are different than the preliminary values released in July because of changes to the model and model inputs. Based on comments received in response to the OPGEE workshop on July 12, 2012, Adam Brandt made several model revisions. The most significant of these revisions are discussed in Appendix E of the model documentation which was released with the third 15-Day Notice. Moreover, in response to stakeholder comments and discussions with crude oil producers, we updated model inputs used for several of the crudes. The detailed model inputs used for the final modeling are presented in the model inputs spreadsheet which was also released as part of the third 15-Day Notice.

The volumes used to assess the 2010 Baseline Crude Average CI are the same as was used for the preliminary calculation released in July 2012. The percentage contribution of each crude to the Baseline Crude Average CI is presented in the supplemental pathway documents for CARBOB and ULSD, which were also released as part of the third 15-Day Notice.

We disagree that representing the crudes produced in California by an average value in the Crude Lookup Table constitutes unequal treatment for several reasons. First, the CI values for the individual fields in California are presented in the supplemental pathway documents for CARBOB and ULSD, which were released as part of the third 15-Day Notice and incorporated into the regulation by reference. Second, it is our understanding that all (or nearly all) crude oil produced in California is refined in California. Therefore we calculated CI values for all California fields (183) that produce more than 1,000 bbls/yr. We then calculated a volume-weighted average CI for CA Crude production which was then used to calculate the 2010 Baseline Crude Average CI. As long as all crude produced in California is supplied to California refineries, it makes no difference mathematically if we use the individual California field CI values or the average California crude production CI value in calculating the Baseline Crude Average and Annual Crude Average CI values. Thirdly, changes to the average CI value for California crude production will require a rulemaking, just as changes to the other values listed in the Crude Lookup Table will require a rulemaking. As part of this rulemaking process to update the average CI value for California crude production, we will recalculate the CI values for all California fields and use these values to update the average. Finally, it is also our understanding that not all crude produced in California becomes a part of a marketable crude oil name (MCON) blend, so calculating MCON CI values for CA production would not be helpful in calculating the 2010 Baseline Crude Average CI. Moreover, we do not have data on the percentage of each California MCON blend derived from constituent crude fields. However, if the oil industry wishes values to be calculated and data is provided as to the percentage of each California MCON blend derived from constituent crude fields, then we can calculate CA MCON CI values.

VI-5. Comment: (b)(2) – A general comment that WSPA continues to make and is effectively ignored by staff, is that if the California Average goes down below the baseline, there should be an allowance for incremental credits if ARB wants to stay consistent with its GHG reduction goals. (WSPA6)

Response: As stated on page 81 of the ISOR, one of the key guiding principles used by staff in evaluating alternative crude oil provisions is "avoiding or limiting incentives to use crude shuffling to generate credits, avoid deficits, or transfer GHG emissions to other jurisdictions to avoid regulation under the LCFS." Allowing for an "incremental credit" to be earned if the Annual Crude Average carbon intensity is reduced below the Baseline Crude Average value will directly incent the shuffling of crude sources in order to earn LCFS credit. The CA Average crude oil approach balances competing goals to discourage an increase in emissions from crude oil production and transport while also minimizing the incentive to shuffle crudes. The approach gives refineries the discretion to shift among available crude sources without incurring an incremental deficit as long as the Annual Crude Average carbon intensity value does not increase relative to the Baseline Crude Average value. In essence, the CA Average approach is designed to increase flexibility for the purchase of crudes and limit the potential for shuffling of crude in order to avoid deficits associated with purchasing individual crudes (as may have occurred under the original HCICO provision) or to generate credits as suggested by the commenter.

VI-6. Comment: Page 73-74 – (b)(2)(A)(1) – Deficit Calculation for CARBOB or Diesel Fuel

The paragraph which starts on page 73 and continues on to page 74 which defines"CIXD20XXCrudeAvg" includes the following sentence:

"CIXD20XXCrudeAvg will be calculated using data for crude oil supplied to California refineries during the calendar year 2012."

We understand this data will include market crude oil names, volumes of these market crudes oils, and the carbon intensity of the individual market crude oils defined in Table 8 of this 15 day package. However we do not see the following in this package:

- A specific regulatory process for ARB to add any new individual crude to the Crude CI lookup table (which is necessary when a crude not supplied to any California refiners in baseline year 2010 is subsequently supplied to one or more California refiners in 2012 or later years).
- A specific regulatory process to revise the CI for a crude already in Lookup Table 8, because:
    - o the OPGEE CI model input data for that crude has changed since 2010 due to changes in production of that crude after 2010, or
    - o the OPGEE CI model input data for that 2010 crude has been found to be incorrect based on the availability of new/additional information on 2010 production of that crude, or
    - o the OPGEE model itself is changed/revised due to new information.
    - o Changes in categories (b) and/or (c) would be expected to impact the original 2010 baseline industry average CI and not just the industry average actual years of the program.

ARB needs to address these issues in rulemaking now, otherwise modifications to Table 8 (other than the posting of individual year average crude carbon intensities from "fixed" individual crude carbon intensities), will require additional formal rulemaking which could delay the publication of the individual year average crude CI's, potentially into the year in which obligated parties must know and account for the generation of any potential incremental deficits. (WSPA6)

Response: Updates or additions to the CI values in the Crude Lookup Table (Table 8) and updates or revisions to the OPGEE model will require a formal rulemaking process. Approval of these updates or additions will be accomplished using an Executive Officer hearing rather than a full Board hearing, pursuant to the delegation of authority from the Board in Resolution 09-31. While we acknowledge that a formal rulemaking process will take more time than a less formal process suggested by commenter, we do not believe that this process will significantly delay publication of the Annual Crude Average CI value for several reasons. First, as part of a formal rulemaking to be initiated early next year, we intend to add CI values to Table 8 for all crudes that have been supplied to California refineries during the time period of 2006 to 2012. The Crude Lookup Table will then have CI values for the vast majority of crudes likely to be supplied to California refineries in the near future. Second, as part of the LCFS reporting requirements the refineries must report crude names and volumes on a quarterly basis. Therefore we should have ample time to conduct a formal rulemaking in the event that a crude not listed in Table 8 is supplied to a refinery. A formal rulemaking to add a few crude CI values to Table 8 can be accomplished fairly quickly. Finally, after the initial few years, we do not intend to revise OPGEE or update the CI values for crudes listed in Table 8 on an annual basis. The frequency of these updates will eventually be reduced to every two or three years.

VI-7. Comment: Pages 74 – 84 - Innovative Crude Production Technologies
WSPA has arrived at a consensus position that we do NOT support the inclusion of the concept of incremental credits for innovative crude oil technology within the

LCFS program because there does not appear to be a way to implement such a program without double counting of credits while correctly calculating the California Average.

WSPA supports voluntary advances in crude oil recovery technologies that reduce CO2 emissions. We believe those benefits should be captured but do not believe a “unique” or “stand-alone” or “one-off” type methodology as proposed is the proper means to capture the benefit. WSPA therefore does not support the inclusion of sections in the regulation that provide details of this approach, and request that this concept be removed.

If, however, ARB decides to not agree to our request, we have several suggestions for revisions to this innovative crude credits area of the regulation. They are:

- Innovative methods should not be restricted to crude oil production using CCS or solar steam generation (as stated on page 75) but these can be used as examples of methods,
- There should be absolutely no double crediting or counting, and,
- The California Average needs to be calculated correctly.

Page 74 - It is not clear how the benefits from innovative crude production methods will not be "credited" twice. Section 95486(b)(2)(A)(1) states the average "...will be calculated using data for crude oil supplied to California refineries during the most recent three calendar years." If a crude is produced using the methods listed, it will be part of the overall crude mix supplied to the refineries; there is no exclusion for crudes produced by "innovative methods". Section 95486(b)(2)(A)(4) page 75 then contains requirements for capturing an additional credit from the use innovative crude production methods. This results in “double- counting” of credits. (WSPA6)

Response: Although we acknowledge that the Innovative Crude Production provision may result in double-counting of emission reductions for limited cases, we disagree with the recommendation that the provision be removed from the regulation.

Allocating LCFS credit for purchasing crudes produced using innovative methods and including the post-innovative method CI for the crude in calculating the Annual Crude Average only results in a double-counting of emission reductions if each of the following is true:

- The crude that is now produced using innovative methods was also a crude used to calculate the 2010 Baseline Crude Average CI value. Double-counting of emission reductions does not occur if the crude was not part of the 2010 Baseline, and even if the crude were part of the 2010 Baseline, double-counting does not occur for volumes supplied to California refineries in excess of those supplied in 2010.
- The reduction in CI for the crude results in a reduction in the incremental deficit. If including the post-innovative method CI value in calculating the Annual Crude

Average does not result in a reduction of the incremental deficit (e.g., if no incremental deficit would occur even using the pre-innovative method CI), then double counting of emission reductions does not occur.

Furthermore, even for those cases where double-counting of emission reduction benefits does occur, we believe the double-counting of benefits is warranted in order to further incent the use of innovative crude production methods that reduce the CI for crude production.

With regard to the comment about not restricting the provision to CCS and solar steam generation, we note that as part of the workshops conducted on March 19 and July 12, 2012, we asked stakeholders to provide recommendations for innovative crude production methods that they wanted included in the regulation. The only recommendations that we received were for CCS and solar steam generation. However, even though the provision currently lists only these two methods, additional methods can certainly be added as part of a future rulemaking.

VI-8. Comment: Page 75 - 95486(b)(2)(A)(4)- Innovative Crude Technologies

- Staff has inappropriately and without explanation reduced the CI reduction threshold by 80% from 5.00 g/MJ to 1.00 g/MJ. This is inconsistent with the treatment for any other fuel under the Method 2A provisions, which require a minimum reduction of 5.00 g/MJ. This inequitable treatment of different fuels must not be permitted under the LCFS.
- Also in this section, detailed calculation methodologies have been added that serve only to replicate calculations that go into the calculation of the California Average crude CI value described elsewhere in the regulations. The California Average calculations are the proper mechanism for inclusion of crude CI changes. The result of this section is a double-counting of crude oil carbon intensity impacts and the awarding of LCFS credits for which there are no actual GHG reductions. This entire section should have been removed, or at the very least had some means inserted that would prevent such improper awarding of credits.
- Obligated parties (refiners) should not be in the position of having credits cancelled if ARB finds out an innovative reduction technology never works as designed or loses its efficacy over time. (WSPA6)

Response: Reducing the threshold for innovative crude methods from 5.00 g/MJ to 1.00 g/MJ does not lead to inequitable treatment of different fuels. First, crude oil is not a transportation fuel. Second, the 5.00 g/MJ threshold applies to the use of Method 2A provisions to customize the CI value for a fuel pathway already listed in Tables 6 and 7 of the regulation. Applications made under the innovative crude production provision are not Method 2A applications. Therefore, we believe that there is no requirement or even rational reason that the same threshold value be applied.

The detailed calculation methodologies alluded to in the second bullet item are required to determine the carbon intensity reduction obtained through use of the innovative crude production method and for determining the credit to be allocated to refiners that purchase the crude. Because LCFS credit will be granted for purchase of these crudes, we believe that a similar level of rigor should be required of the applicant for an innovative crude method as is required of an applicant for a new fuel pathway.

We do not intend to cancel credits if it is determined at a later date that an innovative crude method does not work as designed or loses its efficacy over time. The regulation language includes a provision requiring the applicant to maintain three years of records showing compliance with all "limitations and operational conditions identified by the Executive Officer." If it is determined that subsequent crude production does not comply with these limitations and operational conditions, then purchase of the crude will no longer result in LCFS credits.

VI-9. **Comment:** Page 84 - (b)(2)(A)(4)(d)(v)(I) – Crude Oil Producer Recordkeeping With regard to the record keeping requirements for a crude oil producer to submit an application in order for refiners to receive credits for purchasing crudes produced using innovative crude production methods, the following requirement should be partially deleted as follows:

> *"The annual volume of crude oil produced using the approved innovative crude oil production method and the annual volume of crude subsequently sold in California under the approved innovative crude oil production method"*

It is infeasible to impose the 2nd portion of this requirement on the crude oil producer submitting the application for the innovative crude oil production method, because the crude oil may be sold multiple times, so the crude oil producer may not know how much of this particular crude was actually delivered to refiners in California. Further, it is unnecessary for the crude oil producer to obtain and maintain a record on the volume of this innovative production method crude oil delivered to California, because ARB staff will already have this data via the quarterly reports from California refiners (which contain the market crude oil names and volumes supplied to their California refineries). (WSPA6)

Response: This comment has merit, and after we have received the initial 2013 quarterly reports and determined the reported crude oil information to be complete and thorough, we will propose to revise this requirement as part of a formal rulemaking in 2013.

VI-10. **Comment:** As a supplemental comment to the previously submitted comment letter shown below, WSPA wants to alert ARB to a reference regarding flare combustion efficiency. We are unsure if ARB is aware of this report, but there is a literature review completed by the International Flaring Consortium (IFC), CanmetENERGY, entitled "Emissions from Elevated Flares – A Survey of the Literature – April 2010" (If you have problems accessing the reference please let us know).

The review covers several published studies regarding flaring efficiency. These studies (references compiled in section 6.0 of the report) coupled with the Shell Nigerian flare study referenced in the previous WSPA comment letter below, support a flare combustion efficiency in excess of the 95% that ARB has elected to use in the OPGEE model. These studies support a value of at least 98%. ARB appears to have selected 95% as a conservative value based on just one study in contrast to an efficiency supported by numerous studies demonstrating combustion efficiencies in the range of 98 to 99%. If ARB is going to continue using 95% combustion efficiency as a default, WSPA requests that ARB provide an explanation of what field-specific information could be provided to substantiate a higher combustion efficiency. (WSPA6)

Response: We believe that a flare efficiency of 95 percent is an appropriate default to be used in OPGEE. This value was calculated as part of a comprehensive study of flaring at oil fields in Alberta conducted by Matthew Johnson, Carleton University, and represents the average efficiency for flares in this region. We also note that although the conclusions presented in the literature review conducted by CanmetENERGY (referenced in the comment) state that most studies show a high flare efficiency (>98-99%) for properly designed and operated flares, the range of flare efficiency values published in these studies extend from well below 95 percent to almost 100 percent.

Oil producers desiring to provide evidence of a flare efficiency value greater than the default of 95 percent can provide field-level data such as associated gas composition, fraction of inert diluent, flare exit velocity, wind speed, stack diameter, and specific heating value of the flare gas which can be used in an established parametric model to estimate the flare efficiency.

VI-11. Comment: ARB needs to finalize requirements for crude reporting and credit impacts for 2011. (WSPA6)

Response: This comment is beyond the scope of the Third 15-Day Notice and therefore does not need a response.

VI-12. Comment: ARB needs to provide guidance on what, if anything, the oil industry should be doing for crude reporting and credit impacts for 2012. (WSPA6)

Response: The issue of crude reporting is clarified by the second and third 15-day Change Notices. We are only requiring crude names, country or state of origin, and volumes of crude to be reported quarterly and annually. As for credit impacts, only the base deficit will apply for 2012 and 2013. The 2012 Annual Crude Average CI will be used to determine if an incremental deficit applies in 2014. The 2012 and 2013 Annual Crude Average CIs will be used to determine if an incremental deficit applies in 2015, and the 2012, 2013, and 2014 Annual Crude Average CIs will be used to determine if an incremental deficit applies in 2016.

VI-13. Comment: WSPA believes, due to the lack of detailed field data, that ARB will only be requiring crude MCON identities and volumes for 2013 reporting. We request confirmation of this level of obligation. We note that ARB didn't have more detailed data than this when developing the baseline. (WSPA6)

Response: As discussed above, the second 15-day notice makes this change.

VI-14. Comment: We understand ARB will be the only entity running OPGEE within the context of the LCFS, and ARB will be the official custodian for compliance reasons. Please confirm this understanding. (WSPA6)

Response: ARB will run OPGEE within the context of the LCFS to estimate individual crude CI values that are used to calculate the Baseline and Annual Crude Average CI values. As modified by the third 15-day Change Notice, carbon intensity values for individual crudes are listed in a Crude Lookup Table within the regulation. Changing these CI values or adding to this list will require a formal rulemaking process. However, the model and all subsequent revisions will be publically available and regulated parties and/or crude oil producers are highly encouraged to use OPGEE with field-specific data and submit these analyses to ARB staff for consideration.

VI-15. Comment: We need further details about how a refiner would use the available crude CIs. We need the full list of global crude CIs to purchase crudes intelligently and evaluate (as best we can under the average rule) the impact on our businesses before we purchase crude oil. We reiterate the difficulty ARB's crude oil treatment places on companies that do not have access to detailed crude oil data, nor do they have knowledge about other companies crude purchases in order to be able to assess where the average value may end up every year. (WSPA6)

Response: As modified by the third 15-day Change Notice, carbon intensity values for all crudes supplied to California refineries during 2010 are currently listed in the Crude Lookup Table within the regulation. We have begun estimating CI values for each of the marketable crudes produced globally that are not in the Crude Lookup Table. In order to better meet the needs of the refiners, a prioritized list of MCONs that refiners would like evaluated will be helpful. These lists will help us to prioritize the crudes that we evaluate. Early in 2013 a formal rulemaking will be conducted to add CI values for these additional crudes to the Crude lookup Table. In the meantime, OPGEE is publically available and we have well documented our assumptions and approach to making CI estimates. We do not believe it would be too difficult for refiners to make their own CI estimates to help with crude purchases and in fact, refiners and/or crude oil producers are highly encouraged to use OPGEE with field-specific data and submit these analyses to ARB staff for consideration.

VI-16. Comment: We need more clarity about the workshop references to continuous updates of crude CIs on baseline/annual updates. How and when will ARB notify our industry of MCON revisions or module changes, and what will be the process to update the crude CIs and targets? This will impose additional challenges since a refiner has to plan crude oil selections in a climate of changing CI values. (WSPA6)

Response: Emissions associated with producing individual crudes may change from year to year based on changes in crude production parameters such as flaring rates, steam-to-oil ratios, water-to-oil ratios, etc. Periodically, as part of a formal rulemaking, we will update and/or add to the list of CI values in the Crude Lookup Table. The Annual Crude Average CI value will reflect these changes in individual crude CI values as well as the change in overall crude slate supplied to refineries in the given year. As part of the third 15-day Notice, we added regulatory language describing the process used to calculate the Annual Crude Average CI value.

The Baseline Crude Average CI will only be updated if there is a major update to the model or change in data availability that affects the estimation of crude CI values that are part of the 2010 Baseline. Such an update will also require a formal rulemaking.

VI-17. Comment: False sense of accuracy: OPGEE was created to be a very detailed tool that requires a great many field-specific inputs that are generally unavailable in the public realm. The tool also over-simplifies very complex oil field production processes. As a tool for specific fields that are well-characterized and where field-specific information can be used in lieu of defaults, it may have some utility. However, to estimate average CI values for all crudes run in California refineries, it gives a false sense of accuracy. The output from the model is only as good as the input, and its flexibility to accommodate specific production field details. (WSPA6)

Response: This comment suggests that the model is both too detailed and also too simplified. We agree that the output is only as good as the input, which is why we have repeatedly asked the oil companies to provide data and/or help us to obtain data from third parties. We note that many of the crudes supplied to California refineries are produced by the oil companies that operate these refineries. We have received very limited input from the oil producers, but in those cases where we have received input we have been very willing to modify the modeling in response to the information. In the absence of comprehensive input data for some crudes, we have been careful to use a consistent set of assumptions and default relationships.

VI-18. Comment: Understanding crude data reporting and data availability: There needs to be further discussion about what the regulated parties (i.e. oil companies) are able to provide or acquire in terms of data. Regulated parties are the entities under the jurisdiction of the LCFS, however crude producers are under no obligation to provide competitive, proprietary data. Also, crude is traded on the open market and regulated parties will likely process economic crudes, not just equity production. Many oil companies do not or no longer produce any crude and therefore are concerned that they are placed at a disadvantage in comparison with those companies which may be able to make informed crude selection decisions. (WSPA6)

Response: As modified by the second and third 15-day Change Notices, regulated parties are only required to report crude names, country or state of origin, and volumes for all crudes supplied to their refineries during a given quarter or annual compliance period.

We agree that there needs to be further discussion about availability of data to more accurately estimate the carbon intensity values for some crudes. There are many solutions for the problem of data availability that are largely under the oil industry's control. Oil companies can provide data for crudes they produce, ask for data as part of the purchasing agreement for crudes they do not produce, or purchase data from independent data providers. To date, these independent data providers have been unwilling to provide this data to ARB, citing a conflict of interest with their primary consumers. We have received very limited input from the oil producers, but in those cases where we have received input we have been very willing to modify the modeling in response to the information. In the absence of comprehensive input data for some crudes, we have been careful to use a consistent set of assumptions and default relationships.

VI-19. Comment: Technical Validation: WSPA strongly recommends additional time be provided for technical validation or peer review in addition what has already been done; and more documentation of the model furnished to make additional review time productive. It is difficult to track formulas from sheet to sheet to figure out what the model is doing. If the outputs from the OPGEE tool are adopted without adequate time to error check, it is highly likely that many errors will be discovered throughout the course of the next few years. ARB needs to outline a process for how these future discoveries will be handled, including possible changes to the baseline and yearly targets for each major change. WSPA also requests ARB/Stanford provide an estimate of the tool's uncertainty. (WSPA6)

Response: The Beta version of the model was posted in March 2012 and Draft Version 1.0 was posted in June 2012 along with 160 pages of model documentation and detailed input parameters for each of the crudes analyzed. Unfortunately, there is very little indication that refiners were performing any detailed review of the model until after the July 12 workshop. Refiners had until the end of the third 15-day comment period, October 2, to review the model and provide comments. Therefore, we note that WSPA and its members have had over six months of time for peer review.

As with any new model, we agree that improvements may be discovered throughout the course of the next few years, and we highly encourage stakeholders to engage in discussions with us. One refiner has already done this and we were able to make the model corrections prior to issuing the third 15-day Change Notice. Adoption of additional updates in the LCFS will require a formal rulemaking, which will provide further opportunity for formal review and comment. The Baseline Crude Average CI will only be updated if there is a major update to the model or change in data availability that affects the 2010 Baseline Crude Average CI. An update to the 2010 Baseline will also require a formal rulemaking.

We understand Adam Brandt intends to conduct an uncertainty analysis as part of a future research project. This analysis will focus on variability in CI estimates associated with uncertainty in input parameters. This project would then be published in a peer reviewed journal article. Moreover, Adam intends to submit a research article focused on the accuracy of the model in estimating fuel use and emissions for those few cases where good data exists for both the crude production parameters and the on-site emissions and/or fuel use.

VI-20. **Comment**: Yearly Variation: WSPA requests 2009/2010 results from OPGEE to see yearly variations prior to implementation of the tool. (WSPA6)

Response: We do not have data on volumes of individual crudes supplied to California refineries in 2009. If WSPA, the oil companies, or the CEC provides us with a comprehensive list of 2009 MCONs with volumes, a comparison to 2010 can be done.

VI-21. **Comment:** Co-product credits: The OPGEE model used the substitution method instead of the allocation method where associated gas and liquids co-produced with crudes are assumed to replace NG, NGLs and other products in the existing market. The GHG credits given for these co-products were borrowed from the NG pathway in the GREET model. There are several issues with this approach, since the GHG emissions in the GREET NG pathway were calculated based on the allocation method. Certain pathways under CA LCFS also use the allocation method for crediting certain types of co-products. In addition, substitution only works if the co-product production volume is relatively small compared to the whole market. In some production fields, however, both gas and NGLs are in relatively large quantities and could potentially cause market saturation, where the use of the substitution method would become questionable. As mentioned during the workshop, WSPA suggests the OPGEE model be run with both the substitution and the allocation methods and see if there is a material difference in the results. (WSPA6)

Response: We agree with some arguments made in this comment. We have revised the model to include the option of either allocation or substitution (displacement) for co-products. The default selection will be substitution as this is the method recommended by ISO.

V-22. **Comment:** We request that ARB release a completed model for each crude that leads to the indicated carbon intensity. There is a summary table of final crude CI's, and a summary of crude OPGEE inputs, however, in some cases the tool does not return the same CI when the listed inputs are entered by inexperienced users. It is extremely difficult to evaluate the effectiveness of the tool when it is not known which of the other inputs or defaults have been changed. (WSPA6)

Response: We do not believe it will be productive to provide a completed model for each crude. This would entail providing approximately 250 completed models, as there are 183 carbon intensity values for California fields alone. We will continue to work with interested stakeholders to improve their understanding of the model.

VI-23. Comment: Although the tool allows many features to be turned on or off (such as steam or water flood, downhole pump), there are many components that need that option as well. Some examples include the Amine Treater, Glycol Dehydrator, and the Demethanizer. Some production methods do not have these processes and therefore should not have those GHG emissions attributed to them. (WSPA6)

Response: We agree with this comment and will include the option to turn on/off gas processing units as part of a future version of OPGEE.

VI-24. Comment: The calculations for horsepower to pump fluids into the well appear to only take the pump discharge pressure into account. It is important to consider the pump suction pressure as well, as there are cases of recovered water being sent to a pump at pressure after high pressure separation. (WSPA6)

Response: We agree and corrected this in OPGEE v1.0.

VI-25. Comment: The flaring rates obtained from NOAA are not to be considered accurate on an absolute scale, and are not suitable for regulatory purposes. It is not uncommon for NOAA rates to be off by several hundred percent from reliably measured flaring rates. In the event that flaring rates are also reported to a government agency, those reported numbers should be used in place of the NOAA figures. (WSPA6)

Response: Reliable flaring volumes reported to government agencies will be used in OPGEE when they are available. We note that in the modeling for the 2010 Baseline crudes we used reported flaring estimates for Alaska North Slope (ANS) and several Canadian crudes.

VI-26. Comment: The general assumption that flare combustion efficiency is 95% appears far too conservative, particularly for the larger flares that the NOAA satellites detect. An assumption of 98% flare efficiency would appear more appropriate. For example, there is a Shell Nigerian flaring study that supports 98%. (WSPA6)

Response: We disagree with this comment and believe that a flaring efficiency of 95 percent is more appropriate to use as a default value. The basis for the default flare efficiency value of 95 percent is discussed in the model documentation.

VI-27. Comment: There are a number of crude oil extraction parameters (for example, emissions from drilling, gas compositions, gas-to-oil-ratio, water-to-oil ratio, etc.) which are based on correlations for Canada and/or California, even though California gets most of their imported crude from Alaska, the Middle East, and Central/South America. These correlations may not be applicable to these other locations. (WSPA6)

Response: The smart defaults are designed to give a plausible estimate for important parameters (such as gas-to-oil-ratio [GOR], water-to-oil ratio [WOR], reservoir pressure, etc.) using correlations based on data that is readily available (such as API gravity, field age, and field depth). We agree that the smart default correlations used in the model may not be applicable to every location worldwide. However, we do believe that they provide reasonable estimates to be used in the absence of field-specific data. If we get access to more comprehensive data sets for other regions of the world, we will definitely include these data in future revisions to the smart default correlations.

VI-28. Comment: In the drilling energy plot (Fig 3.1), why is the energy intensity of drilling in 2005 generally higher than the previous years? We would expect energy consumption to trend down over time, other things being equal. (WSPA6)

Response: These data are the available data that were accessible to model builders. Intuitively, there is reason to believe that drilling should become more efficient, but this is not what these data show.

VI-29. Comment: Regarding LUC, the only reference used is Sonia Yeh. Given the debate around this topic, other viewpoints should also be sought out and considered. What, if any, other models/papers for land use change were considered and why were they rejected? (WSPA6)

Response: We believe the LUC paper by Yeh, et al. is the best, most comprehensive estimate of LUC resulting from crude oil production. We are not aware of another comprehensive peer-reviewed study on the topic but will certainly consider other papers if they are provided.

VI-30. Comment: Concerning LUC: a. What time horizon is used? Is it 100 years- like EPA for LUC?
b. Is ultimate restoration of the land at the end of the field life taken into account? (WSPA6)

Response: The time horizon used in the LUC paper by Yeh et al. is 100 years and restoration of the land at the end of field life is taken into account. We note that the calculation of LUC for crude oil production is much different than calculation of LUC for biofuel production. A given oil field can only produce a finite amount of crude oil which determines the energy content used to normalize the up-front LUC emissions. For biofuel production, the assumed time horizon determines the quantity of biofuel that is produced and the energy content used to normalize the LUC emissions. We will continue to research this issue and will make revisions, if deemed appropriate, to the LUC calculations in OPGEE as part of a future model version.

VI-31. Comment: For Production and Extraction, there seems to be no transmission losses between the prime mover and the pump. These may be small, but should be included. (WSPA6)

Response: These losses are believed to be very small. See also the response to comment VI-32**.**

VI-32. Comment: Some of the efficiency defaults (pump, compressor) in Table 3.4 are below the literature range. These should be "typical" (median) values from within that range, not "conservative" values below that range. (WSPA6)

Response: The "typical" values given in Table 3.4 are for new pumps and compressors and do not account for transmission losses between the prime mover and the pump. The difference between the default used in the model and the "typical" values in Table 3.4 accounts for transmission losses, wear, tear, and older equipment. The documentation was updated to better clarify.

VI-33. Comment: To calculate default field age, a discovery to production time lag of 3 years is assumed. At a minimum we believe there should be a range of values which might be dependent on other values and be molded into smart defaults, or that there be the flexibility to enter specific data. Generally, the concept of field age is flawed. A field does not simply appear as fully drilled out in a specific year. Development of a field can continue for decades with infill wells drilled on periodic timeframes. Dependent on management of the field—water flood; gas pressure maintenance, etc.—age is not relevant to the energy load of production. (WSPA6)

Response: The model allows for flexibility to enter the actual field age so the first part of this comment is moot. We agree that a WOR smart default based on some time averaged age of the wells currently in production would likely be better than the default based on absolute field age. However, we are limited by the availability of data to generate the correlation and to use in the model. The production start date was available for the fields used to generate the correlation and is available for many fields worldwide.

We disagree with the comment that age is not relevant to the energy load of production. Most fields show a very obvious trend of increasing WOR with increasing field age, although the slope of this trend definitely varies from field to field. Because energy for production is affected by WOR, we believe field age is an appropriate surrogate for WOR in the absence of field-level water production data.

VI-34. Comment: The default well productivity excludes low productivity US wells. More than half of California's crude comes from California and Alaska. We believe the low productivity wells should be included. (WSPA6)

Response: For both California and Alaska (and all locations in the U.S.), we have the data to use actual values of well productivity for each field. Therefore, we believe it is more appropriate that the default value exclude the low productivity of U.S. wells since the default will only be used for non-U.S. fields where well productivity information may not be available.

VI-35. Comment: When calculating default GOR, API for the pool is calculated by averaging high and low API's. ARB should really average SG, and recalculate API from the average. (WSPA6)

Response: We agree with this comment. This issue is believed to be of minor importance, and it will be fixed in a future version of the model.

VI-36. Comment: When dealing with natural gas byproducts of crude production, how is energy input partitioned between crude and NG, especially if NG is sold or used to generate electricity (in a CoGen plant) which is sold back to the grid? If on-site gas displaces gas which would otherwise have been purchased, is there an offset used? (See comment above under General Comments) (WSPA6)

Response: If natural gas (NG) is sold (exported from the field), then a credit is calculated for the displacement of gas that otherwise would have been produced using dry gas wells. If the natural gas is used to cogenerate steam and electricity then the electricity that is exported from the field receives a credit for displacing electricity that otherwise would have been produced within the electrical power sector. For the model default, we assume displacement of natural gas based electricity. This is the same assumption used for other fuel pathways that coproduce electricity (e.g. Brazilian sugarcane ethanol pathway).

VI-37. Comment: How are upstream emissions for electricity, diesel, gasoline, fuel oil, natural gas, etc. calculated? There should be local input to account for electricity mix or fuel production where it is actually supplied and used. (WSPA6)

Response: Upstream emissions factors are included generally from the GREET model. These sources were updated from GREET to CA-GREET in OPGEE v1.0 to ensure better congruence with other ARB calculations. These sources are documented in the "Fuel Cycle" sheet.

VI-38. Comment: Three diluents for Dilbit are available. What are the CIs? (WSPA6)

Response: The diluent is taken as the average of three diluents from a data table. The diluent CI (upstream) is assumed to be the same as the CI for natural gas (NG). This assumption is made is because diluent is generally natural gas condensate.

VI-39. Comment: Diluent from NGL is counted as external NG. What was the CI of the NGL? (WSPA6)

Response: The upstream CI of NGLs is assumed to be the same as for NG (see above). All NG products (NG, NGLs, diluent) are assumed to have the same upstream emissions.

VI-40. Comment: Natural gas composition for steam generation for TEOR is fixed, when in fact it will vary with location and source. Local inputs should be allowed. (WSPA6)

Response: The source for TEOR fuel can be selected as natural gas (see "Fuel Specs" sheet). The natural gas composition can be varied at will.

VI-41. Comment: What is the 0.5gCO2/MJ "fudge" factor supposed to represent? Why did ARB choose that value since it seems large? (WSPA6)

Response: As noted in the documentation Appendix C, there are dozens of sources that are not included in the model with explicit calculations. Because these emissions are not equal to 0, they must be accounted for with an overall estimate. We assume that these sources sum to 0.5 gCO_2/MJ.

VI-42. Comment: The value denominated in gCO2e/bbl in cell Bitumen Extraction & Upgrading!M164 is transferred to User Inputs & Results'!G188 as gCO2e/MJ. The default sheet is preloaded with a value which suggests that the cell in Extraction & Upgrading is labelled with the wrong units and should be gCO2e/MJ. (WSPA6)

Response: We agree with this comment. This error was corrected in OPGEE version 1.0.

VI-43. Comment: With regard to flaring emissions, the model contains a cell ('user inputs & results'J99) that allows the user to input their own flaring values. However, the cell is not accessed in any calculation. (WSPA6)

Response: We agree with this comment. This error was corrected in OPGEE v1.0

VI-44. Comment: With regard to venting emissions, if the user input cell is set to zero, emissions are still generated due to "default leaks". What is the basis for these "default leaks"? (WSPA6)

Response: Operational venting of gas commonly occurs during normal crude production and surface processing operations and is accounted for by estimates on the VFF sheet of the model. The "User Input" cell labeled "Ratio of venting to oil production" is used when venting is also used as a gas disposal mechanism in lieu of flaring or reinjection. This input may also be used when the exact value for operational venting is known. In this case, the venting calculations on the VFF sheet would be set to zero to avoid double-counting the venting emissions.

VI-45. Comment: In the bitumen module, the upstream emissions of natural gas liquids (NGL's) are assumed to be the same as natural gas. However, NGL's do not undergo the same treatment as natural gas (e.g. there is no point in removing sulfur from a diluent that is going to be added to bitumen) and the transport distances for NGL's are much smaller than those for natural gas (most Canadian gas is transported from Alberta to Ontario, whereas NGL's are mostly produced and consumed within Alberta). (WSPA6)

Response: This issue will be investigated as part of future research and, if deemed necessary, will be corrected in a future version of the model.

VI-46. Comment: Section 3.8 of the User Manual clearly states that "…Blends of SCO and raw bitumen (synbit) or diluent-SCO-bitumen (dil-synbit) are not included in OPGEE" (page 73). However at the same time, the input assumptions and data sheet ARB used for the Albian Heavy Synthetic (AHS) identifies the crude as a "…partially upgraded dil-synbit..." Given this conflict between what OPGEE can model and ARB's description of AHS as a "partially upgraded dil-synbit" how can ARB use OPGEE for crudes identified as "dil-synbits"? (WSPA6)

Response: For most dilsynbits we are able to estimate the CI by estimating the CI for both the dilbit and the synthetic crude and taking a weighted-average based on their percentage contribution to the final blend. In the case of Albian Heavy Synthetic, we worked with Shell Canada to better model the blend.

VI-47. Comment: There is a differing quality of data used for the 2010 baseline—field specific for California from DOGGR reports and simplified MCON estimates for imported crude. The data should be consistent and based on MCONs. Field data will not be uniformly available—even in California.

WSPA requests MCONs for California crude production to facilitate MCON reporting and to understand ARB's knowledge of the complex California crude delivery systems. Most of the OPGEE model processes and defaults are based on California production and the request for tests is so a field-to-MCON evaluation can be completed. (WSPA6)

Response: We do not completely understand this comment. It is our understanding that all (or nearly all) crude oil produced in California is refined in California. Therefore we calculated CI values for all California fields (183) that produce more than 1,000 bbls/yr. We then calculated a volume-weighted average CI for CA Crude production. This value was then used to calculate the 2010 Baseline crude average CI.

It is also our understanding that not all crude produced in California becomes a part of a MCON blend, so calculating MCON CI values for CA production would not be helpful in calculating the 2010 Baseline CI. However, if the oil industry wishes values to be calculated and data is provided as to the percentage of a MCON derived from constituent crude fields, then we can calculate CA MCON CI values.

VI-48. Comment: The vast majority of crudes assessed by ARB staff use many model defaults; however, the available defaults cannot be applied blindly. As an example, Arab Light, which makes up 8% of the 2010 baseline crude volume, is assigned a water-oil ratio of 17.8 which was derived from the “smart default” curve based on field age. This “smart default” was used despite data available to staff that indicates that the water-oil ratio is actually much lower. The chart reproduced below was taken from a presentation by Jacobs Engineering to the Crude Oil Screening Workgroup obtained from ARB’s own web site.

The Jacobs data indicates that the water-oil ratio is about 2 for Saudi Arabian crudes. Staff’s use of the “smart default” value rather than the Jacobs data, combined with the very high well flow rates (5700 barrels per day per well versus a model default of 188 barrels per day per well) for Saudi Arabian production, results in the model estimating an unreasonable CI value (> 200 gCO2e/MJ) when all of the other field-specific inputs and defaults are utilized. Rather than questioning the “smart default”, staff appears to have arbitrarily chosen to increase the assumed well diameter for Arab Light and Arab Extra light to 7.5 inches, which is 3 inches larger than the upper range from the literature reported in the OPGEE documentation. The resulting CI value for Arab Light is 12.5 g/MJ. However, if staff had utilized the Jacobs-based water-oil ratio of 2, then the extraordinary well diameter assumption would not have been necessary and the OPGEE prediction for the CI of Arab Light would have been 7.1 g/MJ - which is still high compared to other estimates, but more reasonable than 12.5 g/MJ.

Given the significant historical consumption of Arab Light by California refiners, WSPA has grave concerns about ARB staff’s application of OPGEE to the calculation of the 2010 baseline and the California average. We are also concerned that if the estimate for such a high profile crude could be so far off, the estimates for other crudes that we have not had time to examine may contain similar errors. (WSPA6)

Response: We agree that the WOR for Arab Light is likely less than the Smart Default value of 17.8 used in the preliminary modeling. Following the workshop we found a few additional literature sources supporting a lower WOR for some fields in Saudi Arabia. Therefore, for the final modeling we assumed a WOR value of 2 for Saudi oil production. The well diameter was also reduced to 3.75 inches, which is within the range supported by the model documentation.

VI-49. Comment: Basrah Light, which makes up 8% of the 2010 California baseline crude volume, is also assumed to come from wells with a high flow rate (1500 barrels per day per well with a water-oil ratio of 14.4, again based on the "smart default" curve as a function of field age). In that case, ARB has assumed a well diameter of 4 inches. What was the basis of the well diameter estimate? Given that there is a significant difference between the water-oil ratio assumed for Saudi Arabian production from the "smart default" versus available data, we are concerned about the validity of the use of the "smart default" for Basrah Light. Has ARB attempted to validate this estimate with other sources of data? (WSPA6)

Response: We agree that the WOR for Basra crude is likely less than the Smart Default value of 14.4 used in the preliminary modeling. Following the workshop we found a few additional literature sources supporting a lower WOR for some fields contributing to the Basra crude blend. Therefore, for the final modeling we assumed a WOR value of 6 for Basra oil production. The well diameter was also reduced to 3.25 inches, which is within the range supported by the model documentation.

VI-50. Comment: Another parameter that was modified for cases in which wells have a high flow rate is the Productivity Index, which has a baseline value of 3.0. Arab Light and Arab Extra Light are assumed to have a Productivity Index of 75, and Basrah Light is assumed to have a Productivity Index of 15. What is the basis of these estimates? (WSPA6)

Response: The higher productivity index values that we assumed for Middle East crudes is based on an internet source (http://www.gregcroft.com/ghawar.ivnu) which presents productivity index values for the Ghawar field ranging from 31 to 141 BOPD/psi. Assuming this source provides an upper range for productivity index, we increased the productivity index up to a value of 15 for crudes produced with very high flow rates per well. We believe that it is logical to assume that these fields will have a higher productivity index in order to support such high flow rates.

VI-51. Comment: The water-oil ratio has a significant impact on the model results, but the data used to derive the "smart default" values as a function of field age are highly variable and exhibit extreme scatter (see Figure 3.11 in the OPGEE documentation). How confident is ARB that these "smart defaults" are accurately estimating the water-oil ratio for specific fields, particularly in Saudi Arabia and Iraq? Also, the field age appears to be based on the oldest well ever drilled in a given field (e.g., for Arab Light, the assumed age is 56 years). Given the long development timelines and massive size of the fields in some of these locations (e.g., Ghawar in the case of Arab Light), a field age would be much more reasonably based on an average age of the wells as they were brought on stream. As discussed earlier, Arab Light is an example of an unreasonable "field" age being used to calculate an unreasonable (and data-contrary) "smart default" for the water-oil ratio that produces a CI estimate that is out of line with all other work. (WSPA6)

Response: The smart defaults are designed to give a plausible estimate for important parameters (such as GOR, WOR, reservoir pressure, etc.) using correlations based on data that is readily available (such as API gravity, field age, and field depth).

We are not confident that the WOR smart default is accurate for any given field, however we do believe that it provides a good estimate for WOR to be used in the absence of other data. Most fields show a very obvious trend of increasing WOR with increasing field age, although the slope of this trend definitely varies from field to field. Because energy for production is affected by WOR, we believe field age is an appropriate surrogate for WOR in the absence of field-level water production data.

The data used to generate the WOR smart default correlation is based on the production start date so production start date is the proper input variable to be used in making the WOR estimate. We agree that knowing the average age of wells as they are brought on stream and developing a correlation using this average age may be more appropriate. However, the average age of wells is not known for either the fields used to develop the correlation or for the fields producing the marketable crudes of interest.

VI-52. Comment: CARB has added substantial new provisions in 95486(b)(2)(A)(4) enabling companies to apply to CARB for the ability to obtain credits for projects that reduce the carbon intensity of crude oil during production. Such projects are termed "innovative crude production methods" in the regulation. It is BP's understanding that any company using a crude where such a technology has been installed and CARB has approved a CI reduction for that crude may generate credits in proportion to the volume of that crude. CARB has also proposed to incorporate the post-control CI value into the annual CA average crude CI calculation. Several new provisions have been added by CARB in an attempt to outline the approval process for these reduction projects to ensure a robust analysis of the CI reduction.

However, BP found no safeguards in the new provisions that would prevent a potential scenario, described below, incenting increased volumes of crudes where such a CI reduction has occurred; but, at the same time, causing the CA average CI to increase. Such an increase to the average runs counter to CARB's policy objective to prevent or minimize increases in the average CI of crudes used in California.

The scenario that BP is concerned about is a case where a company processing a particular volume of crude with a high CI in California successfully applies an innovative CI reduction project with the appropriate CARB approval. For example, a company has been processing 30,000 bbls/day of a 20 CI crude that has now been reduced to a 15 CI crude using an innovative technology. If that company or other companies begin processing additional volumes of this particular crude (i.e., 60,000 bbls/day), these same companies could be foregoing even lower CI crudes to take advantage of the specific credit opportunities afforded those who process crudes to which these innovative production techniques have been applied. Unfortunately, such a scenario would lead to an increase in the average CI of the crude being processed in California despite the improved CI on the particular crude. BP requests that CARB consider adding additional provisions to safeguard against such a scenario. (BP3)

Response: We acknowledge BP's concern regarding such a scenario and will consider modifications to the regulation language to safeguard against such a scenario as part of a future rulemaking. We further note that this comment illustrates a disadvantage of the CA Average approach that has been pointed out in other comments, namely that the potential incremental deficit associated with an increase in the Annual Crude Average CI is spread amongst all refiners, thereby diluting the incentive to avoid purchase of higher CI crudes. The scenario illustrated in this comment would not likely occur using the Hybrid or Company-specific crude approaches as the incremental deficit is calculated using the company-specific crude slate, which likely removes any advantage of replacing lower CI crudes with higher CI innovative crudes.

As discussed on pages 77 to 84 of the ISOR, we evaluated six alternative approaches for the treatment of crude oil in the LCFS regulation, including two approaches providing an individual compliance option, the company specific and hybrid approaches. We acknowledge that lengthy lists of advantages and disadvantages could be generated for each of the alternatives, however based on the review presented in the ISOR, staff concluded that the California Average approach was preferable. Although the Board approved the California Average approach at the December 2011 hearing, Board members were sensitive to the points made in this comment and have asked staff to evaluate and propose, as appropriate as part of a future rulemaking, an option for individual regulated parties to have their deficits for gasoline and diesel determined on a refinery-specific basis that accounts for the carbon intensity of domestic and imported crude oils, intermediate products, and finished fuels.

VI-53. Comment: Despite the addition of substantive provisions guiding the use of innovative crude technologies for reducing CI, the current provisions fall short of a robust defensible methodology. There is no monitoring to ensure the innovative reduction technology remains in use—the crude supplier could switch it off once the application has been approved and the EO has entered CI with and CI without the technology into the look-up tables. BP requests that CARB add provisions to the regulation ensuring that the equipment approved as resulting in a CI reduction continue to operate in a manner consistent that yields the claimed reductions. This is the equivalent of ensuring that the CI reductions are 'permanent' similar to other emission reduction credit programs.

The methodology does not specify whether the proof requires the use of OPGEE design parameters or actual measured parameters over a period of time beyond the initial application. A crude oil should not be classed as innovative based solely on design parameters, but should only be classed as innovative based on a reasonable period of operation. BP requests that CARB add appropriate safeguards to the regulation to ensure that real operating data be assessed to confirm the reduction claimed in the application. This is the equivalent of ensuring that the CI reductions are 'real' and 'verifiable' consistent with other emission reduction credit programs. (BP3)

Response: We disagree with this comment. Section 95486(b)(2)(A)4.d.iv. states "*If the Executive Officer finds that an application meets the requirements set forth in subsection 95486(b)(2)(A)4, the Executive Officer will take final action to approve the crude oil carbon intensity value and the associated innovative crude oil production method, describing all limitations and operational conditions to which the innovative crude oil production method will be subject, by amending this section 95486 in accordance with Government Code section 11340, et seq."* Additionally, section 95486(b)(2)(A)4.d.v. requires that the applicant maintain records for at least three years showing "*compliance with all limitations and operational conditions identified by the Executive Officer in paragraph iv, above*" and requiring that "*these records shall be submitted to the Executive Officer within 20 days of a written request received from the Executive Officer or his/her designee, provided the request is made before the expiration of the period during which the records are required to be retained.*" We believe that this language provides safeguards that will ensure that the CI reductions associated with implementing the innovative method are real and are maintained after approval. Moreover all stakeholders will have opportunity to provide input into developing the "limitations and operational conditions" as final approval of the innovative method will occur by a formal rulemaking.

VI-54. Comment: We appreciate that ARB staff strives to encourage innovation and investment in technology that will reduce the carbon intensity of fuels, including carbon capture and storage (CCS) technology and support the principle of regulated parties being able to earn LCFS credits if they obtain crudes from sources that have implemented innovative methods such as CCS to reduce emissions for crude oil recovery. As we have previously commented, we still believe it is premature to set a minimum threshold carbon intensity reduction in order for an innovative method for crude oil production to qualify for these LCFS innovative credits, because any threshold could actually act as a barrier to the developments of such projects and actually act to discourage work in this field. However, we are pleased to at least see, in the section of this third 15-day package addressing crude oil production from innovative methods, that ARB has revised the proposed minimum threshold from 5.00gCO2e/MJ to 1.00 gCO2e/MJ in order for the carbon intensity reductions to qualify for innovative LCFS credits. (SHELL2)

Response: We appreciate your support for the innovative crude provision and the reduction of the threshold value from 5.00 to 1.00 g/MJ. We do not agree that establishing a minimum threshold value to qualify for credits will provide any additional barrier to development of emission reduction projects. Any improvement in the carbon intensity of a crude will be captured in the calculation of the Annual Crude Average carbon intensity value. The innovative method provision only provides an additional incentive to use innovative methods that provide a substantial reduction in carbon intensity for crude production.

VI-55. Comment: GlassPoint commends the Air Resources Board for adopting the Low Carbon Fuel Standard (LCFS) and establishing market-based mechanisms to achieve reductions in the carbon emissions of liquid transportation fuels. In addition, we appreciate the Air Resources Board and staff for continuing to work in the development of the Carbon Intensity Lookup table and guidelines for establishment of pathways to comply with the Low Carbon Fuel Standard.

GlassPoint strongly supports the mechanisms proposed in the Third 15-Day Modified Regulation Order for the Low Carbon Fuel Standard, which could provide credit for innovative crude production methods, including solar steam generation, which deliver reductions in carbon intensity.

The specific mechanism incorporated in the Third 15-Day Modified Regulation Order would provide market-based returns to those who invest in innovative technology for reducing emissions, supporting the deployment of such technology, and would provide further indirect benefits to all producers and users of transportation fuels in California which include:

- The establishment of lower-cost pathways for achieving LCFS compliance
- Reductions in the blended-average intensity score of California petroleum
- Reductions of the local costs and impacts associated with combustion emissions. (GP)

Response: We appreciate the commenter's support for the LCFS and the innovative crude provision.

VI-56. Comment: As outlined in detail in Kern's comments on the Second Notice of Public Availability of Modified Text to the LCFS dated August 24, 2012, Kern's greatest concern regarding the proposed modifications continues to be CARB' s failure to address the defects of the current "average refinery" approaches in the LCFS regulations and proposed modifications. Specifically, the "average" approach results in a flawed High Carbon Intensity Crude Oils (HCICO) accounting for low-volume refiners and, similarly, a disproportionately high Carbon Intensity (CI) determination for finished fuels for low-energy use, low-complexity refiners. The resulting hardships to low-volume, low-energy use, and low-complexity refiners like Kern caused by the generalizations within the "average" approaches have been well-documented and substantiated, as well as acknowledged by CARB. Kern continues to urge CARB to address these defects as we move into implementation of LCFS because these defects now pose a real threat to Kern and similarly situated refiners' bottom lines. (KORC5)

Response: This comment refers to comments made by Kern Oil in response to the Second 15-Day Notice. Please see the response to those comments.

VI-57. Comment: As noted in Kern's previous comment letter dated August 24, 2012, the Second Notice of Public Availability of Modified Text failed to incorporate the most recent data representing 2010 as the baseline year for CA-Average Crude CI as opposed to 2009. The current modifications being proposed have since updated the baseline year for CA-Average Crude Carbon Intensity to 2010 as well as the corresponding target CIs for finished fuels. Kern wishes to express its appreciation for CARB's consideration of points made and updating of the baseline year to 2010. (KORC5)

Response: We appreciate the commenter's support for the update of the Baseline Crude Average CI value to the year 2010.

VI-58. Comment: Although the language in the previous Second Notice of Modified Regulations was generic in allowing for models other than CA-GREET, the currently proposed language now specifically references OPGEE as an approved model for estimating crude oil CIs. Although the previously modified text did not specify a particular model, it was Kern's understanding from public workshops hosted by Staff in March and July 2012, that Staff would seek approval to use the recently developed OPGEE model. Use of the OPGEE model, as developed by Stanford University for CARB, would give Staff and those seeking specific new pathway approvals an alternative to the CA-GREET model for determining crude oil CIs.

As noted in our previous comment letter dated August 24, 2012, while Kern has no specific technical objection to the OPGEE model at this time, there are generally many concerns and unanswered questions surrounding the use of the model:

1. The model is still in infancy stages, having just been developed in 20 12; the beta version was introduced in March 2012, with updates made and the next version released in June.
2. The model has been built on a number of assumptions because many of the data inputs necessary are not publicly available information.
3. There has been no opportunity to prove or ground-truth the model for accuracy. Without specific field operating data to input, developers have not been able to compare outputs using assumptions to outputs using known data. Without this opportunity, how can anyone be sure the results are reliable?
4. There has been no information made available to compare CIs of crude oils established using the CA-GREET model to CIs of the same crude oil established with OPGEE. What makes OPGEE more accurate, warranting that it replace CA-GREET for the crude oil production and transport CI value?
5. If the CIs of fuels in the regulations have been determined solely using CA-GREET, then are we even comparing apples to apples by having new CIs for crude oil baseline/annual compliance and new fuel pathways established based on a separate or possibly multiple model outputs?

CARB should consider and respond to the above comments, and provide additional supporting documentation justifying the use of and substantiating output results from the OPGEE model. (KORC5)

Response: The CA-GREET model uses a very simplistic method to calculate the carbon intensity of crude oil. The only inputs to the CA-GREET model are the crude recovery efficiency and fuel shares for crude oil production. In applying this model, ARB staff assumed model input values for each of the different crude slates to calculate a weighted-average carbon intensity.

To refine this approach, ARB staff tasked Stanford University researchers to develop a tool that uses process parameters (steam-to-oil ratio, reservoir depth, etc.), crude origins, and other applicable metrics to calculate carbon intensities of individual crudes. The researchers conducted extensive searches to obtain information relevant to appropriate calculation methodologies and inputs required for the model. In areas where data have been limited, the researchers used best engineering judgments to estimate default inputs to the resulting OPGEE model. The methodology and inputs used in the OPGEE model are described in detail in both the model and the accompanying documentation.

Compared to CA-GREET, the OPGEE model is a much more sophisticated approach to estimating carbon intensity for crude oil production. It does not use a generic average approach for a whole region (or regions), but rather uses much more detailed inputs to calculate carbon intensity for crude recovery and transport. Similar to the process of adding land use change carbon intensity (using the GTAP model) for biofuels, the output from the OPGEE model will replace the crude production + transport components of the well-to-wheel analysis from CA-GREET, and the remaining components of the pathway analysis from the CA-GREET model will be retained.

VI-59. Comment: The currently proposed modifications add a "Table 8" entitled "Carbon Intensity Lookup Table for Crude Oil Production and Transport." Kern notes that the crude oil CIs identified on Table 8, however, appear to be an incomplete picture of the actual crude oil being utilized by California refineries. For example, Table 8 lists only two domestic crudes - the California Average Production and the Alaska North Slope. Absent from the proposed modifications is any explanation of how CARB calculated the California Average Production CI - for example, what specific California oil fields were considered, the time frame over which the considered production data was collected, or the averaging methodology. On July 10, 2012, CARB staff previously released a draft table entitled "Table 2: Preliminary Carbon Intensity Values for California Fields (Fields with greater than 2000 BOPD)", which included California field specific CI values ranging from 1.6 (Beta) up to 28.6 (Placerita). The wide CI discrepancy from field to field highlights the need for California field specific CI data to be included in the regulations to give a more accurate picture of an individual refiner's crude slates. Moreover, such an average necessarily assumes that the proportion of these crudes processed by California refiners will not vary from year to year, which obviously is not the case. The fact that Staff already has the field specific CI values makes the failure to include those values in the regulations even more unjustifiable.

Further, it is highly unlikely that California refiners only ran domestic crude oil from two different states - California and Alaska - as currently presumed in the modifications. The existing regulations did not mandate reporting of individual Marketable Crude Oil Names (MCON) to CARB, as would now be required by the proposed modifications. However, CARB distributed voluntary surveys to refiners in 2011, which Kern presumes was the source of the individual California field data listed in Table 2 and presumptively those surveys also listed domestic crude sources in addition to the two identified in the proposed modifications. It is unclear why this additional detail is not included within the currently proposed modifications.

Kern urges CARB to expeditiously release CI values for additional domestic MCONs and update Table 8 to include California field-specific values as opposed to the currently proposed statewide average, to enable refiners to make informed business decisions going forward with regard to their crude oil slates. (KORC5)

Response: The data on imported crudes and their respective volumes used to calculate the Baseline Crude Average CI value was provided to ARB by the California Energy Commission and was not obtained through the survey referenced in this comment. The sources for crude data are noted in the Supplemental Pathway Documents for CARBOB and ULSD which were released as part of the Third 15-Day Notice and incorporated into the regulation by reference. These data from the CEC did not include any domestic crude other than those produced in California and Alaska. Response of refiners to the survey noted in the comment was not complete, and therefore we were unable to use the survey responses as a data input to the process.

A description of how ARB calculated the Baseline Crude Average and California Average Crude Production CI is provided in the Supplemental Pathway Documents for CARBOB and ULSD. Moreover, the detailed model inputs used in OPGEE to calculate CI values for 183 fields in California and the sources for these data are presented in the "Final Inputs OPGEE" spreadsheet which was also released as part of the Third 15-Day Notice. The resulting CI values for all fields in California producing more than 2,000 BOPD and their respective oil production rates are presented in Table 2 of the Supplemental Pathway Documents for CARBOB and ULSD. The California Average Crude Production CI is a production-weighted average of the CI values for the 183 California fields.

We disagree that representing the crudes produced in California by an average value in the Crude Lookup Table (Table 8) is "unjustifiable". First, the CI values for the individual fields in California are presented in the Supplemental Pathway Documents for CARBOB and ULSD which were released as part of the Third 15-Day Notice and incorporated into the regulation by reference. Second, it is our understanding that all (or nearly all) crude oil produced in California is refined in California. Therefore we calculated CI values for all California fields (183) that produce more than 1,000 bbls/yr. We then calculated a volume-weighted average CI for CA Crude production which was then used to calculate the 2010 Baseline Crude Average CI. As long as all crude produced in California is supplied to California refineries it makes no difference mathematically if we use the individual California field CI values or the average California crude production CI value in calculating the Baseline Crude Average and Annual Crude Average CI values. Finally, we intend to update the California Average Crude production CI periodically just as we intend to update the all other crude CI values in Table 8 periodically. Moreover, changes to the average CI value for California crude production will require a rulemaking just as changes to the other values listed in the Crude Lookup Table will require a rulemaking. As part of this rulemaking process to update the average CI value for California crude production, we will recalculate the CI values for all California fields.

As part of a formal rulemaking to be initiated early next year, we intend to add CI values to Table 8 for all crudes that have been supplied to California refineries during the time period of 2006 to 2012. The Crude Lookup Table will then have CI values for the vast majority of crudes likely to be supplied to California refineries in the near future. All refiners are encouraged to provide names of additional crudes that they would like added to the Crude Lookup Table. We particularly encourage the commenter to supply ARB with a list of additional domestic crudes that should be added to the Crude Lookup Table.

VI-60. Comment: Kern respectfully continues to urge the Board and Staff to address the unjustified disproportionately negative impact of the current regulations on low-volume, low-energy-use, and low-complexity refineries, like Kern - the timeliness of which is imperative. The cumulative effect of CARB' s continued failure to address LCFS regulatory shortcomings is in the inability for California refiners to access compliance, adequately budget, or make informed business decisions under LCFS. As always, we are committed to working with Staff throughout this regulatory process. (KORC5)

Response: This comment is outside of the scope of the Third 15-Day Notice. Although no further response is required, staff wishes to inform the commenter than it continues to conduct technical analyses related to low-energy-use refineries and may return to the Board with recommendations on this issue during a future rulemaking.

C. Other Comments

VI-61. Comment: Page 6 - Section 95480.3(b). Carbon intensity is not the only parameter that needs to be defined by opt-in parties. Paragraph (3) correctly specifies the appropriate EER for that option, but paragraphs (1) and (2) should also state that the EER appropriate to the chosen CI must be used. (WSPA6)

Response: We do not believe that it is necessary to modify paragraphs (1) and (2), as the regulation is explicit as to the appropriate EERs to use in those situations.

VI-62. Comment: Page 68 - Table 7 is missing biodiesel CI values from the guidance that was issued in July. (WSPA6)

Response: Section 95486(a)(5) specifies that a default value from table 7 for ULSD may be used with the Executive Officer's approval, this is consistent with the advisory noted by the commenter. The advisory allows a regulated party to use the value for ULSD in Table 7 as a default CI value for biomass-based diesel for which the CI could not be reasonably determined.

VI-63. Comment: Page 93 - 95486 (f)(3)(A)(1)- Application of ASTM standards. The revised provision no longer requires that a fuel be compliant with applicable ASTM standards, but instead references that the fuel could alternately be compliant with "…generally recognized consensus standards." WSPA recommends that the alternative to ASTM compliance be re-phrased as follows: "…generally recognized consensus standards from an ANSI recognized standards development organization". Adding this phrase would cover the SAE International standards likely referenced for alternative fuels. (WSPA6)

Response: We believe that the phrase "generally recognized consensus standards" serves the purpose of which it is meant to—that is—to provide flexibility without over-complicating the rule.

VI-64. Comment: RPMG also wishes to convey our concern with the length of time it has taken to implement the proposed amendments to the LCFS program as they pertain to oxygenate for blending and biomass-based diesel. RPMG has been closely monitoring the progression of these regulations since early 2010. We understand changes of this magnitude take time to design and effectively implement. It is our opinion the regulated industry has reached the point where we are now ready to have Section 95480.2 "Persons Eligible for Opting into the LCFS Program" and Section 95481 "Definitions and Acronyms" fully adopted and approved by CARB. If CARB requires more time to craft and implement Section 95482 "Average Carbon Intensity Requirements for Gasoline and Diesel" and Section 95486 "Determination of Carbon Intensity Values", we would respectfully request CARB to further consider amendments to these sections separate from the proposed amendments to Sections 95480.2 and 95481. By separating these topics we feel it would help the industry adjust to the proposals made that are of a less controversial nature. (RPMG)

Response: All the amendments, including Section 95480.2 and 95481, as well as Sections 95482 and 95486, will be implemented in January 2013.

APPENDIX A - References

These references support the data found in OPGEE v1.0.

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