The Impact of the Low Carbon Fuel Standard and Cap and Trade Programs on California Retail Diesel Prices

California Trucking Association

4148 East Commerce Way
Sacramento, CA 95834
916 373-3500
www.caltrux.org

Prepared by:
STONEBRIDGE ASSOCIATES, INC.

4333 Jan Drive
Carmichael, CA 95608
916 524-8195
www.stonebridge.associates.com

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I. Executive Summary

California has embarked upon a Greenhouse Gas Reduction (GHG) policy path that may have large negative impacts on the state's diesel market and the diesel prices California consumers and businesses may face. The impacts are associated with possible outcomes of the California Air Resources Board's (ARB) Low Carbon Fuel Standard (LCFS) in combination with the impacts of ARB's Cap and Trade program.

One possible LCFS outcome, the Compliance Outcome, would occur if the alternative fuels required for compliance are available. If that is the case, there will be significant diesel price increases from incorporating those alternative fuels. These diesel price increases will be added to price increases that will be imposed by ARB's Cap and Trade Program.

CTA estimates that the combined effect of the two programs could increase California-only retail diesel prices by $2.22/gallon by 2020, raising diesel prices by 50 percent to $6.69/gallon. These California-only diesel price increases would have a very damaging effect on California's recovering economy.

The other possible LCFS outcome, the Non-Compliance Outcome, would occur if the program is infeasible because the alternative fuels needed for compliance under the program's regulatory timeline are unavailable in sufficient quantities. The diesel price impacts of such an outcome would depend upon how the ARB and the programs' regulated parties respond to those circumstances.

In the event that a Non-Compliance Outcome does begin to unfold, which could occur as early as 2014 or 2015, CTA is concerned that ARB is not prepared to take prompt action to protect the state's recovering economy from the damaging costs that would emerge from an unbounded LCFS credit market[1].

A. Compliance Outcome

Under the Compliance Outcome the combined effect of the LCFS and Cap and Trade programs would add an additional $2.22/gallon to California diesel prices, increasing retail diesel prices by 50 percent to $6.69/gallon by 2020.

The average price difference between California and neighboring states would be $2.33/gallon, taking into consideration California's $0.11/gallon higher average diesel tax rate.

These higher California-only diesel costs will create a substantial cost bubble around California where inside the bubble diesel prices will be significantly higher than in the rest of the country.

[1] ARB's enforcement of the LCFS has been temporarily enjoined by the U.S. District Court. See Case 1:09-cv-02234-LJO -GSA Document 259 Filed 12/29/11 Page 1 of 38. A discussion of the decision is provided in Appendix A.

Higher California-only diesel prices will impose a significant burden on the California economy. Apart from their wider economic consequences, higher diesel prices will make California a less attractive destination for containerized imports from the Pacific Rim and reduce the economic benefits, employment, income and state and local taxes generated in California by that import trade.

The impact of higher retail diesel prices on containerized imports will be magnified by the competitive pressures on California ports due to the 2014 completion of the Panama Canal expansion project. The Panama Canal project will double the capacity of the canal and amplify by 50 percent containerized import losses caused by retail diesel price increases.

Between 2015 and 2020, the cumulative impacts of containerized import losses caused by retail diesel price increases could be 616,922 lost jobs, $68.5 billion in lost state domestic product, $21.7 billion in lost income and $5.3 billion in lost state and local taxes.

By comparison California job losses due to the current recession between 2007 and 2010 were 1,304,600 jobs. The projected cumulative loss of 616,922 jobs, solely due to retail diesel price increases, would equal nearly half the state's total recession-related job losses.

Many of the job losses will be in the economically significant logistics industry, the industry responsible for almost 14 percent of the California economy. The logistics industry consists of the industry groups responsible for the shipping, receiving, processing, and storage of goods, and is an important remaining source of middle-class entry jobs.

The California-only diesel price increases will competitively disadvantage the trucking and warehousing services of California logistics companies. These cost disadvantages will allow out-of-state companies to effortlessly strip away the California industry's commercial transportation business along the state's central I-5 and US 99 trade corridors.

The California-only diesel price increases will also impose higher costs on essential California commercial activities which depend upon logistics industry services, such as those that affect the price of food and other essential services.

The timing of these job losses could not be worse. They are set to begin in 2015, about the time the California economy is projected to be recovering from the current recession. The adverse effects of ARB's diesel price increases could set back California's economic recovery for many years.

These wider economic consequences will probably not be offset by additional employment in alternative-fuel related industries, since California does not manufacture alternative fuel vehicles and has a very limited capacity to manufacture alternative fuels.

Moreover, these California-only diesel price increases will create a negative economic impact without providing a corresponding public health benefit, unlike air quality policies that target health-related criteria pollutants.

B. Non-Compliance Outcome

Non-compliance, or infeasibility, will occur when the alternative fuels needed to achieve the program's objectives are not available at the times needed and/or in the qualities and quantities required. At this time, based on available data, CTA expects that in the absence of timely action by ARB, infeasibility will occur by 2015.

Infeasibility is the almost inevitable consequence of an inherent flaw in the LCFS compliance framework. Each year the LCFS's declining annual carbon intensity target paradoxically lowers the credit-generating ability of renewable fuels to offset the increasing credit deficits of conventional fuels.

The possibility of compliance, therefore, would depend upon very large, albeit unlikely, improvements in the credit-generating ability of renewable alternatives. These very large carbon-intensity improvements, and the significant investments needed to make such improvements possible, would have to materialize in less than a decade.

The impacts of LCFS infeasibility are likely to appear in the cost of program credits in the 2014-2015 time frame. Scarce, high-priced program credits will threaten the price and availability of fuels, especially diesel fuel.

The LCFS credit market as currently structured will almost certainly become a target for speculators who will acquire credits in anticipation of the program's infeasibility. The incentive for this speculation, and its potentially disastrous impacts, will be amplified by the program's total lack of credit cost controls, credit holding limits, or real-time credit market information system, as well as its primitive, untimely manual credit verification systems.

Would-be speculators will also be encouraged by the ARB's historical willingness to ignore the consequences of policy-driven cost impositions on the petroleum industry. ARB's assumption appears to be that the petroleum industry has no alternative but to comply with whatever cost impositions ARB places on the industry, an assumption based on a belief that all such costs can be passed on to consumers and therefore will not fundamentally alter those companies' business practices.

However, the LCFS will create winners and losers within the state's petroleum industry. Oil companies will differ in their capacity to address the requirements and pass on costs of the LCFS. To deal with these differences, they will resort to strategies that make sense from an individual business perspective, even if such strategies might have negative public consequences.

In order to improve their competitive positions in a tight LCFS credit scenario, some oil companies may attempt to remain in compliance by simply manufacturing less fuel for in-state use, exporting the remainder to other markets. This behavior would curtail in-state supply and drive up in-state fuel prices, increasing the already high California refining margin on remaining sales. This strategy would most likely be targeted at diesel fuel.

As challenging as the increased fuel costs of a compliance outcome would be to California industry, the possibility of even higher fuel prices associated with tightened supplies and unchecked credit prices could lead to even greater reductions in Pacific Rim imports, significantly damage the state's critical logistics industry and create even greater problems for California's economic recovery.

C. ARB Response Raises Concerns

ARB's response, to date, to concerns voiced by its Advisory Panel during its recently completed LCFS program review, regarding the unrealistic character of ARB's LCFS implementation scenarios, creates serious concerns.

The likely availability, or capacity to use, the necessary alternative fuels within the program's remaining 9-year time frame is quite low, yet that key fact is not reflected in ARB's public analyses of the program.

ARB's staff analyses propose compliance scenarios that are highly unrealistic, put forth price forecasts that deliberately underestimate likely program costs by underestimating alternative fuels costs, constructively misinterpret the requirements and over-estimate the costs of the federal RFS2 alternative fuels program, and summarily dismiss concerns about the LCFS program's infeasibility as merely a matter of opinion.

When infeasibility becomes a reality, ARB's swift and considered intervention to mitigate spiking credit costs will be crucial to safeguarding the California economy from widespread harm.

Yet the market structure so far created by ARB is woefully undeveloped and its unhurried pace of future development appears to reflect ARB's view that non-compliance will be an unlikely event.

Moreover, there is a concern that ARB's response to high credit costs will *not* be to moderate those costs, since high fuel costs are intended to drive adoption of alternative forms of transportation and alternative fuel use.

D. Policy Recommendations
There is a need for greater legislative involvement in the ARB's GHG reduction programs. In particular, the Legislature should:

1. **Institute Greater Policy Oversight over ARB.** The Legislature should review and consider oversight options that ensure that the GHG reduction costs imposed by ARB programs are affordable.

   There is currently no effective policy oversight over ARB. Despite the formal requirement that ARB consider input from stakeholders, there is no institutional framework that assesses the ARB's actions or lack thereof regarding that input.

   ARB's critical planning oversights, its concealment of potentially high costs that could be imposed by the LCFS and Cap and Trade programs and concerns about ARB's potential unpreparedness to mitigate unchecked credit market shortages raise questions about continuing to support ARB's independent ability under AB 32 to impose significant costs on the California economy.

2. **Improve ARB's Governance Structure.** The Legislature should review the ARB's governance structure and consider strengthening it by empowering part-time board members with independent analytical resources and support capabilities so they can play a more effective role in policy decisions.

3. **Remove Diesel from the LCFS Program.** The Legislature should review and consider whether it makes sense to continue to include diesel fuel in the LCFS program.

   Diesel GHG emission reductions that would result from the LCFS are so minor, they account for only 1.7 percent of all recommended GHG reduction measures.

   Yet, retaining diesel in the LCFS program raises the prospects of the significant economic damage and the hundreds of thousands of lost jobs that would be caused by retail diesel price increases.

4. **Require Regulatory Costs to be Imposed as Tax-Exempt Surcharges.** The Legislature should review and consider requiring that the LCFS and Cap and Trade program costs ARB imposes on the costs of fuels be reflected in the retail prices of transportation fuel in the form of tax-exempt, per-gallon surcharges in the same manner that other state and federal fees and excise taxes are currently posted and imposed.

   This would prevent these regulatory costs from being included in refiners' fuels costs and thereby being magnified in their impact by being themselves taxed. ARB-imposed diesel costs have a 17 percent higher impact at the retail level compared to if they had been imposed as tax-exempt surcharges.

Imposing program costs in the form of tax-exempt surcharges would also avoid the competitive effects created by differences in companies' capacity to absorb program costs without engaging in extraordinary measures that might adversely affect California fuels markets.

Finally, requiring that ARB LCFS and Cap and Trade program costs be imposed in the form of tax-exempt surcharges would create greater transparency for the public and Legislature regarding the costs of ARB GHG reduction programs, especially as revenues from those programs are considered for future spending.

II. Introduction

The purpose of this report is to assess the potential effects of the ARB's Low Carbon Fuel Standard and Cap and Trade program on the cost and availability of diesel fuel.

The cost and availability of diesel fuel is a significant issue for the economy of California because crucial elements of the economy, specifically Pacific Rim imports, global and domestic imports and exports, and economic activities that depend upon the state's logistic industry are all directly affected by diesel costs.

The report is organized as follows:

- **III. Programs Background** provides basic information, and discussions of their interrelationship, on the key programs analyzed, including the ARB's LCFS program, the federal Renewable Fuel Standard (RFS2) program, and the ARB's Cap and Trade program.
- **IV. LCFS and Cap and Trade Retail Diesel Price Impact Analysis** discusses the issues involved in cost analyses, contrasts available cost analyses and provides CTA's estimate of the potential joint retail diesel price impacts of the LCFS and the Cap and Trade programs.
- **V. Economic Impacts of Retail Diesel Price Increases** discusses the potential impacts of the joint LCFS and Cap and Trade retail diesel price impacts on containerized imports from the Pacific Rim into California as well as potential impacts on the state's important logistics industry.
- **VI. Renewable Fuels Required for LCFS Feasibility** provides information about the renewable fuels industry and the likely availability of the type and quality of the renewable diesel fuels required for the LCFS program to be achievable in its current form.
- **VII. LCFS Non-Compliance and Its Potential Consequences** discusses estimates of when the LCFS program's infeasibility is likely to occur, the potential impacts of a non-compliance outcome, including a discussion of ARB's LCFS market structure, and potential oil industry responses to credit shortages.
- **VIII. Concerns regarding ARB's Lack of Preparedness** discusses ARB's performance to date, in particular its failure to respond to information that has been provided to it regarding the implausibility of the LCFS schedule, and its lack of preparation to mitigate the impacts of potential credit market shortages.
- **IX. Policy Recommendations** identifies and summarizes policy recommendations that the findings of this study suggest.
- **X. Conclusions** summarizes the findings of the report.

III. Background

This section introduces the LCFS program and related programs, including the federal RFS2 program and the ARB's Cap and Trade Program, all of whose contributions and interactions need to be understood.

The contributions of the LCFS and Cap and Trade programs to diesel prices are additive because the programs are independent. Therefore, costs from each program will be added to fuel prices.

The relationship of the LCFS and the federal RFS2 programs is different. The federal RFS2 program requires refiners to blend specified percentages of types of alternative fuels in the fuels they manufacture.

Because the RFS2 program is a nationwide program, refiners are not required to blend any particular proportion of their RFS2 requirement in any specific state.

ARB interprets RFS2 requirements as meaning that California refiners must at minimum include a California-sized[2] proportional amount of RFS2-required alternative fuels in the fuels they manufacture for sale in California.

That interpretation is not correct. The costs of fuels that LCFS requirements cause refiners to blend in California, which they would not otherwise blend in California, are costs attributable to the LCFS.

A. Low Carbon Fuel Standard Program

The Low Carbon Fuel Standard (LCFS) program was developed by the California Air Resources Board (ARB) to help meet the requirements of AB 32[3], California's 2006 greenhouse gas reduction law.

AB 32 requires ARB to adopt and enforce a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions levels prevalent in 1990. That historic level is required to be achieved by 2020.

AB 32 directs ARB to adopt regulations to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions. The bill also authorizes ARB to adopt market-based compliance mechanisms to achieve the 2020 goal.

The LCFS itself was not specifically required or mentioned by AB 32. The LCFS was required by 2007 Executive Order S-01-07[4]. That Executive Order specified that:

- A statewide goal be established to reduce the carbon intensity of California's transportation fuels by at least 10 percent by 2020;

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[2] Approximately 10 percent.
[3] AB 32, (Nunez. 2006)
[4] http://www.arb.ca.gov/fuels/lcfs/eos0107.pdf

- A Low Carbon Fuel Standard for transportation fuels be established for California;
- The LCFS apply to all "providers" (refiners, blenders, producers or importers of transportation fuels in California);
- The LCFS be measured on a "full fuels cycle" basis; and,
- Provider obligations be met through market-based methods in which providers exceeding LCFS requirements receive credits applicable to future obligations or tradable to providers not meeting the LCFS.

However, the Executive Order did not specify that the costs of achieving the LCFS' carbon reduction goal be affordable.

AB 32 required ARB to develop a scoping plan to identify measures that would be used to achieve the 2020 goal. Among the plan's proposed emission reduction measures was the LCFS.

According to the scoping plan, the LCFS is slated to be responsible for a reduction of 15 million metric tons of CO2 equivalent (MMTCO2E) or 8.6 percent of the projected reductions from all recommended measures. Projected reductions from all recommended measures totaled 174 MMTCO2E[5].

Most LCFS reductions would come from gasoline which is responsible for 80 percent of GHG transportation fuel emissions. The remaining 20 percent would come from diesel. Diesel GHG emission reductions attributable to the LCFS would be 1.7 percent of all recommended GHG measures.

1. LCFS Compliance Methodology The LCFS achieves GHG emission reductions by incrementally reducing the allowable carbon intensity (CI) of transportation fuel produced and sold in California. Regulated parties are required to comply with an annual average CI standard for the total amount of fuel they sell.

Under the proposed regulatory schedule, the allowable carbon intensity[6] of transportation fuels decreases each year, beginning in 2011, until gasoline and diesel carbon intensities in 2020 are each, presumably, reduced by 10 percent from 2010 levels[7].

In each year, the carbon intensity of each supplied fuel is compared to the LCFS CI requirement for that year. Fuels that have carbon intensity levels below the CI requirement generate credits. Fuels with carbon intensity above the CI requirement generate credit deficits.

[5] Climate Change Scoping Plan, California Air Resources Board, December 2008
[6] Measured in g CO2e/MJ.
[7] The current regulatory schedules for diesel and gasoline are presented in Appendix B.

Total credits and deficits are determined based on the amount of fuel sold, the difference between the carbon intensity of each fuel and the annual CI target, and the efficiency by which end-use vehicles convert the fuel into useable energy.

a. ***Options for LCFS Compliance*** Fuel providers have several options to meet the regulation. They may:

- Supply a mix of fuels above and below the standard that, on average, equal the required carbon intensity.
- Only provide fuels that have lower carbon intensity than the standard, for example, by blending low carbon ethanol into gasoline, or renewable diesel fuel, if available, in diesel fuel.
- Purchase credits generated by other fuel providers to remedy deficits from their own production. For example, a fuel provider may choose to purchase credits from a fuel provider that has credits from selling electricity used in a plug-in hybrid vehicle.
- Apply credits "banked" in years in which they exceeded the standard to offset shortfalls in a current year.

Credits are based upon a fuel's energy content and the difference between the fuel's carbon intensity and the annual carbon intensity target.

In the case of conventional diesel, whose carbon intensity will always be greater than the annual target, every gallon of conventional diesel sold in California will contribute to a negative credit balance for entities refining and selling that fuel.

That negative credit balance must be offset either by lower CI substitute diesel fuels or by blending conventional diesel with other lower CI diesel fuels.

b. The LCFS's Inherent Structural Flaw The LCFS program has an inherent structural flaw. Each year the difference between the CI of conventional diesel and the CI of the continually declining annual requirement increases, meaning the credit deficit associated with each conventional diesel gallon sold will get larger.

By the same token, each year the positive difference between the CI of biofuel additives or substitutes and the CI of the continually declining annual requirement get smaller.

This means that the capacity of additives and substitutes to offset the increasing credit deficits from conventional diesel becomes smaller each year as the CI target is lowered.

This significant progressive degradation of the value of non-petroleum alternative fuels reduces the time frame during which specific alternatives will be commercially viable and thereby undermines incentives for alternative producers to invest in additional production capacity.

This inherent structural flaw also creates compliance problems. Compliance requires continual large improvements in the CI value of required alternative fuels. ARB tries to magically solve this problem in its compliance scenarios by claiming several somewhat unlikely possibilities:

- An unspecified process whereby the CI values of substitutes get progressively lower each year,
- The use of greater proportions of lower-CI fuel blends than can be used by vehicles and
- Greater overall availability of lower-CI substitute fuels than will likely be available, given various technology and infrastructure constraints.

The problem for diesel is that the lower-CI fuels, specifically biodiesel and cellulosic diesel, which might be blended with or substituted for diesel, are and will be limited in their capacity to offset negative diesel credits.

2. Carbon Intensity The lifecycle carbon intensity of a fuel determines the quantity of credits its use will produce that would offset the negative program credits associated with conventional fuel usage.

A fuel's lifecycle carbon intensity is determined in two phases. The first phase, direct lifecycle, accounts for all of the direct GHG emissions associated with producing, transporting, and using the fuel. The second phase accounts for land use changes associated with its production.

a. Direct and Indirect Lifecycle Carbon Intensity Direct lifecycle CI can be affected by farming practices, crop yields, energy used for harvesting and transportation, type and efficiency of the production process, and end-use vehicle efficiency.

The second, indirect phase considers GHG effects caused by related land use changes. An indirect land use change is triggered when an increase in demand for a crop-based biofuel begins to drive up prices for the required feedstock crop. This price increase causes farmers to devote a larger proportion of their cultivated acreage to that feedstock crop.

The lowest-cost way for many farmers to take advantage of higher commodity prices is to bring non-agricultural lands into production. However, such land use conversions release the carbon sequestered in soils and vegetation. The resulting carbon emissions are the "indirect" land use impact of increased biofuel production.

The calculation of indirect land use change impacts is highly controversial because there are significant technical disagreements about the most accurate means of assessing them.

Another significant issue is that land-use calculations boost the CI of specific renewable fuels to levels more equivalent to those of conventional petroleum-based fuels. These higher CI attributions have significant commercial implications for the relative attractiveness and utility of specific renewable fuels under the LCFS.

b. Federal Injunction on Land-use Change Calculations The federal court injunction on the enforcement of California's LCFS specifically called out the use of land use change calculations as illegal under the U.S. Constitution's Commerce Clause.

Specifically, the court found that the LCFS's requirement that land use changes be considered in calculating carbon intensity necessarily regulates conduct that occurs almost entirely outside of California's boundaries[8].

3. Relevant Renewable Fuels From the perspective of the logistics and goods movement industry, the relevant renewable fuels needed to lower the net CI of diesel fuel and which will affect the cost and availability of diesel fuel are biodiesel and renewable diesel.

In the longer term, credits from electricity and natural gas use may make contributions to lowering overall CI, to the extent that significant numbers of those vehicles in the goods movement sector that are capable of using these fuels are added to fleets.

However, because that shift would require widespread and costly fleet conversion and infrastructure change, lower-CI diesel blend stocks such as biodiesel and renewable diesel will be the primary means used to meet CI targets for the foreseeable future.

4. Regulated Parties In general, the LCFS places compliance obligations initially on regulated parties, such as fuel producers and importers, which are legally responsible for the quality of transportation fuels in California. Table 1 lists the regulated parties for LCFS fuels.

[8] Case 1:09-cv-02234-LJO -GSA Document 259 Filed 12/29/11 Page 1 of 38

Table 1. LCFS Regulated Parties

Fuel	Regulated Parties
Gasoline, diesel, and liquid blendstocks (including oxygenates and biodiesel)	The producer or importer of the fuel or blendstocks.
Fossil fuel-derived compressed natural gas (fossil CNG)	The utility company, energy service provider, or entity that owns fuel dispensing equipment.
Other gaseous fuels (biogas/biomethane, hydrogen)	The entity that produces the fuel and supplies it for vehicular use.
Electricity	The entity or party supplying the electricity which has assumed the compliance obligation.

5. Opt-In Provisions for Non-Obligated Parties The LCFS regulation includes an opt-in provision that recognizes that certain alternative fuels have life-cycle carbon intensities that meet compliance standards. These fuels are:

- Electricity;
- Hydrogen and hydrogen blends;
- Fossil CNG and LNG derived from North American sources;
- Biogas CNG; and
- Biogas LNG.

Non-obligated providers of these fuels may opt-in to the program. By opting in, an entity becomes a regulated party under the LCFS regulation and is required to meet the LCFS reporting obligations and requirements. Non-obligated parties that opt in to the LCFS program will be parties that expect to generate LCFS credits.

B. Federal RFS2 Program

The LCFS was designed to take advantage of renewable fuel requirements established by the federal RFS2 program. RFS2 is the successor to the 2005 federal RFS program that established the first U.S. renewable transportation fuel mandate by requiring specific renewable fuels to be blended by fuel providers into transportation fuels[9].

RFS2, established in 2007 under the Energy Independence and Security Act (EISA):

- Expanded the RFS program to include diesel,
- Increased the volumes of renewable fuel required to be blended into transportation fuels,
- Established new renewable fuel categories with specific volume requirements, and

[9] Created under the 2005 Energy Policy Act (EPAct)

- Required EPA to use lifecycle performance standards so each renewable fuel would emit fewer greenhouse gases than the petroleum fuel it replaced.

The RFS2 program is important to understanding the LCFS because in determining the cost of the LCFS program, the costs of the RFS2 program need to be excluded since they are costs that would be incurred in the absence of the LCFS.

These costs must reflect the fact that the RFS2 program is national, giving refiners flexibility in determining where and how they comply and incur costs.

Additionally, the RFS2 program incorporates mechanisms that adjust annual requirements and provide incentives for alternative fuel production.

1. RFS2 Requirements RFS2 consists of four separate nested annual requirements. The nested aspect means that fuel satisfying the higher requirements (referring to the order of the bulleted list below) can be applied to the lower requirement.

So, for example, compliance with the 1 billion gallon biomass-based diesel requirement can be also applied to the advanced biofuel requirement and the renewable biofuel requirement because biomass-based diesel meets the Advanced Biofuel 50 percent threshold and exceeds the Renewable Biofuel 20 percent threshold. All volumes[10] are in ethanol equivalent gallons.

- Biomass-Based Diesel: 1 B gallons by 2012 and beyond
  - Includes biodiesel and “renewable diesel,” if not co-processed with petroleum
  - Must meet a 50 percent lifecycle GHG threshold

- Cellulosic Biofuel: 16 B gallons by 2022
  - Includes fuel produced from cellulose, hemicellulose, or lignin, such as cellulosic ethanol, BTL[11] diesel and cellulosic gasoline.
  - Must meet a 60 percent lifecycle GHG threshold

- Advanced Biofuel: Total of 21 B gallons by 2022 (Minimum of 4 B gallons additional)
  - Anything except corn starch ethanol
  - Includes sugar cane ethanol, cellulosic biofuels and biomass-based diesel
  - Must meet a 50 percent lifecycle GHG threshold

[10] Except biomass diesel
[11] BTL stands for biomass to liquid, another term for cellulosic diesel.

- Renewable Biofuel: Total of 36 B gallons by 2022 (Minimum of 15 B gallons additional)
  - Ethanol derived from corn starch–or any other qualifying renewable fuel
  - Must meet 20 percent lifecycle GHG threshold-only applies to fuel produced in new facilities

The standards are translated into annual percentages so that every regulated provider can know the minimum volume of renewable fuel that it must ensure is used in its overall transportation fuel mix. The final 2011 overall RFS2 volumes and standards were:

- Cellulosic biofuel: 6.6 million gallons; 0.003 percent:
- Biomass-based diesel: 800 million gallons; 0.69 percent;
- Advanced biofuel: 1.35 billion gallons; 0.78 percent; and,
- Renewable fuel: 13.95 billion gallons; 8.01 percent.

As will be discussed later, EPA has modified the original RFS2 schedule each year to reflect changes in its expectations for biofuel development. These changes have important consequences, in turn, for the feasibility and costs impacts of the LCFS[12].

a. Relationship of LCFS and RFS2 Programs The relationship of the LCFS and RFS2 programs requires interpretation. The RFS2 program requires refiners to blend specified percentages of types of alternative fuels in the fuels they manufacture.

The RFS2 nationwide program allows refiners to comply wherever in the U.S. they choose.

Companies that have a national presence will be able to comply with the RFS2 through any of the facilities they operate. This is an advantage for companies that have refining facilities located near sources of biofuel production.

However, ARB interprets RFS2 requirements as meaning that California refiners must at minimum include a California-sized[13] proportional amount of RFS2-required alternative fuels in the fuels they manufacture for sale in California.

The ARB interpretation is not correct. The RFS2 makes no such requirements.

California refiners' RFS2 costs will be based upon the quantities of alternative fuels refiners choose to blend in California.

The costs of fuels that LCFS requirements cause refiners to blend in California, that are different than refiners' choices, are costs attributable to the LCFS.

[12] The current RFS2 schedule is presented in Appendix C.
[13] Approximately 10 percent.

2. RIN Program An important element of the RFS2 program is its Renewable Identification Number (RIN) program. Total consumption of biofuels is scheduled to increase to 36 billion gallons per year, if the timetable set in the EISA is to be met. To ensure that fuel blenders meet this volume, EPA creates incentives by means of a market for biofuel RINs.

Every purchased gallon of biofuel has a unique RIN associated with it. Gasoline producers and importers are assigned a total number of RINs that they must submit to EPA each year to comply with RFS2. Producers and importers can obtain those RINs by buying biofuels and keeping the RINs associated with those purchases, and/or they can enter the RIN market and purchase the RINs.

RIN sellers are companies that purchase biofuels but have no obligation to meet an EPA requirement or who purchase more biofuels than they need to fulfill their EPA requirement. For either of these reasons, they will have RINs that can be sold to other parties requiring more RINs to achieve compliance.

RINs can also be created, priced and sold by EPA when the annual requirements created in the previous year turn out have been too large.

The value of RINs is designed to approximate the difference between the cost of ethanol and the cost of gasoline. Allowing regulated parties to purchase RINs to comply with the RFS2 is an alternative to actually purchasing and blending the specific fuels.

The demand for RINs increases when the quantity of biofuels purchased is insufficient to meet the RFS2 standard. An increased demand for RINs increases the RIN price, which improves the relative attractiveness of buying biofuels directly *instead* of RINs.

For example, if the wholesale price of ethanol is $2.00 per gallon but the wholesale price of gasoline is only $1.50, the demand for ethanol would be low. However if with every $2.00 gallon of ethanol a buyer obtains a RIN with a value of $0.25 per gallon, then the net cost of ethanol would be $1.75 per gallon, still higher than gasoline but more attractive than in the absence of the RIN value.

If the RIN price is $0.75 per gallon, then the demand for $2.00 ethanol would be increased because the net cost of using ethanol to meet fuel demand would be only $1.25 per gallon, compared to $1.50 for conventional gasoline.

EPA expects the RIN price will settle at a level at which the demand for ethanol is just sufficient to meet RFS2 requirements[14].

[14] "Intricacies of Meeting the Renewable Fuels Standard," Iowa Ag Review, Spring 2009, Vol. 15 No. 2

Every physical gallon of renewable fuel produced or imported into the United States is assigned a unique RIN for compliance. Equivalence values for every physical gallon of renewable fuel represent the number of gallons that can be claimed for compliance purposes, based on its energy content compared with ethanol. For example, a gallon of conventional ethanol counts as 1 RIN, a gallon of biodiesel counts as 1.5 RINs, and a gallon of renewable diesel counts as 1.7 RINs[15,16].

RIN prices are market driven and affected by changes in the prices of both crude oil and biofuel feedstocks. In most cases, higher crude oil prices lead to an increased willingness to pay for more expensive substitute biofuels, thus lowering the price for RINs. When crude oil prices decrease, consumers' willingness to pay for biofuels also decreases and RIN prices increase[17].

Because feedstock prices account for a large share of biofuel production costs, a surge in feedstock prices will increase biofuel production costs. Thus, when feedstocks become more expensive, the prices of RINs increase. Lower feedstock prices reduce production costs and RIN prices.

3. Adjustability of RFS2 Requirements Each year EPA is required to assess the potential availability of required biofuels and adjust the following year's requirement accordingly. This provision ensures that regulated parties are not faced with unrealistic requirements for blending renewable biofuels that are not available.

a. History of EPA RFS2 Adjustments Since 2010, limited cellulosic biofuel availability has resulted in the EPA reducing its target volumes for that fuel by 95 percent or more and issuing end-of year compliance credits when even its reduced prior year forecasts proved too high.

In 2009, EPA reduced the 2010 required volume of cellulosic biofuels by 95 percent from 100 million gallons to 5 million gallons. However, that reduced level overestimated the volume of cellulosic fuel produced in 2010 for transportation purposes. To compensate for low cellulosic volume, the EPA made cellulosic biofuel waiver credits available to obligated parties for end-of-year compliance at $1.56 per gallon.

In 2010, EPA reduced the 2011 required volume of cellulosic biofuels by 97 percent from 250 million gallons to 6.6 million gallons. However, compliance with even this highly reduced requirement was infeasible. To remedy this situation,

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[15] "The Renewable Identification Number System and U.S. Biofuel Mandates," Lihong McPhail, Paul Westcott, Heather Lutman, A Report from the Economic Research Service, USDA, November 2011.
[16] The EPA has interpreted the biomass-based diesel volume mandate as diesel volume rather than as ethanol equivalent volume. Thus, although 1 gallon of biodiesel counts as 1.5 RINs for the advanced biofuel and the total renewable fuel standards, it counts as 1 gallon for the biomass-based diesel mandate.
[17] A CEC chart of historical RIN prices can be seen in Appendix D.

EPA made cellulosic biofuel waiver credits available to obligated parties for end-of-year compliance at $1.13 per credit.

In 2011, EPA reduced its 2012 cellulosic biofuel target by 98 percent from 500 million gallons to 8.65 million gallons. Cellulosic biodiesel credits will sell for $0.78/gallon.

C. California Cap and Trade Program

AB 32 authorized the ARB to establish a cap-and-trade program that caps the aggregate GHG emissions from covered entities responsible for 80 percent of the state's GHG emissions. The ARB will issue carbon allowances that these entities will be able to buy and sell. The number of allowances issued will be smaller than the amount of emissions that would otherwise be produced, thereby lowering overall emissions.

A covered entity can comply with the Cap and Trade regulation by obtaining one allowance (or credit) for each ton of CO_2 that it emits in a specified compliance period. The price of allowances will be set in a trading market. As the cap declines, increased allowance scarcity will increase the price of each credit.

The Cap and Trade credit market is a separate market from the LCFS credit market. Credit purchase costs stemming from both markets will be reflected in retail fuel prices.

The ARB will initially allocate and auction Cap and Trade emission. There will be private credit trading markets, including the secondary market for trading credits directly between covered entities and a derivatives market which will use financial contracts for hedging and investment.

Although trades will take place through privately operated markets, ARB requires that trade information be reported to it for input into a tracking system before the trade can be completed. However, the bulk of the oversight responsibility will fall to third parties with whom ARB will contract.

The ARB has designed its Cap and Trade program to limit the volatility of compliance instrument prices. The ARB's plan to keep allowance prices from spiking too high is to provide a limited number of allowances from three ARB allowance reserves, sized in total at 4 percent of total allowances.

These allowances will be available to covered entities in case there is an unexpectedly short supply that could otherwise drive allowance prices to unacceptably high levels. The maximum prices for these allowances for each of three reserves are set respectively at $40, $45, and $50 per metric ton of CO_2 in 2012. Minimum allowance prices will be $10 per metric ton of CO_2.

These maximum and minimum prices will increase by 5 percent per year plus adjustments for inflation. The maximum prices will serve as partial ceilings on allowance prices. However, if the reserves are exhausted, ARB regulations do not set any ceiling on the price of allowances, meaning there is potentially no limit to how high credit prices could rise[18].

a. Motor Vehicle Emissions Under ARB's Cap and Trade program, beginning in 2015, refiners and importers of gasoline and diesel will be required to purchase credits to offset the GHG emissions of all California motor vehicles, in proportion to the amount of fuels they sell in the state.

This requirement will create costs for refiners that will add to the cost of gasoline and diesel fuels. The cost of this requirement will be assessed in the next section.

[18] "Evaluating the Policy Trade-Offs in ARB's Cap-and-Trade Program," California Legislative Analyst, February 9, 2012.

IV. LCFS and Cap and Trade Retail Diesel Price Impact Analysis

This section presents CTA's LCFS cost analysis and contrasts it with LCFS cost analyses that have been developed by ARB, CEC and Sierra Research. The section also analyzes the potential retail cost impacts of ARB's Cap and Trade program requirement that refiners purchase credits sufficient to offset all California motor vehicle GHG emissions.

A. LCFS Cost Analysis Factors

The LCFS rule is complex and has many interacting parts. An analysis of the cost impact of the rule on diesel is dependent upon the assumptions used for a number of key factors, including:

1) CI values of fuels blended with or substituted for diesel,
2) Costs of required fuels compared to the cost of diesel,
3) Amounts of specific fuels used,
4) Annual CI requirements,
5) RFS2 requirements and costs, and
6) Infrastructure Costs

1. CI Values of Fuels Blended With or Substituted for Diesel. Assumptions about the CI value of specific fuels and how those CI values might change over time will affect the number of credits their use will produce.

2. Cost of Required Substitute Fuels Compared to the Cost of Diesel
Substitute fuels more expensive than diesel, blended with or substituted for diesel, will increase the cost of diesel. Less expensive fuels will have the opposite impact. Forecasts of substitute fuel costs will have a significant effect on program cost assessments.

3. Amounts of Specific Fuels Used There are limits on the amounts of fuels that can be used to generate credits. Biodiesel can currently only be used in blends up to 5 percent (B5) without violating engine warranty restrictions.

Newer vehicles that would be able to use higher biodiesel blends would account for only a small percentage of diesel consumption and would require access to a separate dispensing system or private refueling capacity.

There is no limit on the amount of renewable or cellulosic diesel that could be used to meet diesel demand because its use replaces diesel on a one-for-one basis.

4. Annual CI Requirements The annual CI target affects the ability of any particular alternative fuel to help the program meet its compliance goals. The LCFS incorporates an incrementally more difficult set of annual CI targets, with the majority of the CI decrease slated to occur in the final five years of the program.

The lower the target, the greater the negative credit requirement created by petroleum fuels and the less lower-CI fuels can offset the negative credit requirement. Therefore fuels added to meet any latter year program deficits must have extremely low CI values to have any productive effect.

5. RFS2 Requirements and Costs LCFS costs are those imposed in addition to costs associated with meeting RFS2 requirements. RFS2 requirements and costs are based upon the extent that refiners choose to meet their national RFS2 requirements in California.

6. Infrastructure Costs The primary feedstock for domestic biodiesel production in the U.S. has historically been Midwest soybean oil. Biodiesel is typically blended with diesel fuel at the refinery terminal as tanker trucks are loaded for delivery to retail stations.

For this to occur, B100 biodiesel must be stored in segregated tanks and special blend equipment used to control blend proportions. The infrastructure for this process is not widely available in California. A similar infrastructure requirement would apply to cellulosic diesel and renewable diesel.

A transportation infrastructure would have to be created to bring biodiesel, cellulosic diesel and renewable diesel to California refineries in required quantities[19]. The costs of this infrastructure must be included in a cost analysis.

B. LCFS Cost Analyses

Three public LCFS compliance cost analyses were evaluated by CTA:

- The LCFS cost analysis presented in ARB's staff report[20],
- The LCFS cost analysis prepared by CEC staff[21], and
- The LCFS cost analysis prepared by Sierra Research[22].

CTA also prepared its own LCFS cost analysis. The features and assumptions used to develop each cost analysis are presented below.

1. ARB LCFS Cost Analysis

- ARB priced the compliance scenarios it developed to demonstrate hypothetical ways to achieve the LCFS rule.
- The price forecasts ARB developed and used did not include any CI premiums or factors reflecting RIN prices for different alternative fuels.

[19] See Appendix E for information on infrastructure costs.
[20] *Low Carbon Fuel Standard* 2011 Program Review Report, Final Draft, December 8, 2011
[21] The CEC Cost Analysis is described in the Excel spreadsheet CEC 2011–23-14 Biofuel values
[22] Review of CARB Staff Analysis of "Illustrative" Low Carbon Fuel Standard (LCFS) Compliance Scenarios, Prepared by Sierra Research, Inc. for the Western States Petroleum Association, February 21, 2012.

- All the ARB compliance scenarios showed comparable overall price impacts because the amount of alternative fuels used to achieve the diesel contribution to overall compliance was limited to 20 percent of diesel demand.
- The 20 percent restriction on alternative fuels also constrains the cost impacts associated with latter year requirements for low CI-alternatives.
- ARB LCFS program price impact forecasts are for “wholesale” prices, reflecting only the cost to refiners of biofuels, and do not estimate retail impacts which would include the effects of federal, state and local taxes.
- ARB included a $0.22 infrastructure charge equal to that calculated by EPA in its RFS2 economic impact assessment. For gasoline, the charge was attributed to RFS2 costs; for diesel, the charge was attributed to LCFS costs.
- The RFS2 cost assumptions used by ARB reflect its incorrect claim that RFS2 costs will be those associated with California-sized proportions of RFS2 requirements.
- In addition, ARB has calculated RFS2 costs using unmodified statutory RFS2 requirements, which require 10.5 billion gallons of cellulosic diesel production by 2020.
- These two latter assumptions systematically underestimate LCFS program costs.
- ARB has, to date, refused to release the Excel spreadsheets it used to calculate RFS2 and LCFS costs.

2. CEC LCFS Cost Analysis

- The CEC prepared three scenario cases. Only one scenario, Case 3, was comparable to the ARB compliance scenarios. However, Case 3 goes out of compliance in 2019 and 2020 because of an insufficiency of renewable fuel credits. This results in an underestimate of LCFS costs.
- There were no limits in the CEC analysis on the amount of alternative fuels that could be blended with or substituted for diesel. By 2017, almost 30 percent of diesel volumes in Case 3 were accounted for by alternative fuels.
- CEC staff used its published fuel price forecasts which included CI premiums. The premiums were based upon current and projected RIN values for each alternative fuel.
- No infrastructure costs were included in the CEC cost analysis.
- The CEC staff never published overall LCFS fuel price impacts.
- For reasons that were never clear, the CEC abruptly delayed further public staff analyses of LCFS feasibility and costs.

3. Sierra Research LCFS Cost Analysis

- Sierra Research priced the ARB scenarios to determine the cost of the LCFS programs.

- Sierra Research used the CEC high price alternative fuel and diesel price forecasts to price the ARB scenarios, amplified by the addition of an additional layer of CI premiums.
- No infrastructure costs were included in the Sierra Research analysis.
- Sierra Research's RFS2 forecast assumes that California's proportional share of EIA's forecasted US biodiesel consumption will be equivalent to its RFS2 requirement.
- Sierra Research's RFS2 costs do not include any cellulosic biodiesel.
- Sierra did not translate its diesel cost analysis into a diesel price impact.

4. CTA LCFS Cost Analysis
The CTA compliance cost analysis included the following elements:

- CEC Case 3 scenario, with sufficient diesel alternatives added to achieve full diesel compliance through 2020.
- CEC high price forecasts, unmodified.
- RFS2 costs based upon CEC supply forecasts of California-only biodiesel and tallow–based biodiesel.
- EPA infrastructure costs applied to all diesel alternatives.
- Calculation of LCFS diesel price impacts
- Federal, state and local taxes applied to reflect the retail impact of diesel cost increases[23].

C. Comparison of Price Impact Analyses Only two of the four cost analyses described above were translated by their originating organizations into LCFS price impacts: ARB's cost analysis and CTA's cost analysis. Table 2 provides a comparison of the ARB and CTA wholesale price impacts.

A comparison of the two analyses is helpful in understanding the extent to which ARB's has systematically hidden the potentially significant impacts of the LCFS rule on wholesale diesel prices.

As can be seen in Table 2, the impacts of using a compliant CEC scenario with no arbitrary alternative fuels limit, using CEC alternatives prices that include CI premiums, and more correctly reflecting RFS2 program requirements and costs, shows that the impacts of the LCFS program on diesel prices could be quite significant.

Table 2. Comparison of LCFS Wholesale Price Impact Analyses: CTA study vs. ARB Report[24].

Source	2012	2013	2014	2015	2016	2017	2018	2019	2020
CTA Study	$0.06	$0.11	$0.19	$0.41	$0.46	$1.11	$1.20	$1.31	$1.47
ARB Report	($0.04)	$0.02	$0.08	$0.10	$0.17	$0.24	$0.23	$0.22	$0.20

[23] http://www.api.org/Oil-and-Natural-Gas-Overview/Industry-Economics/Fuel-Taxes.aspx
[24] Average of all diesel scenarios

D. Cap and Trade Diesel Program Costs

Under the Cap and Trade program, beginning in 2015, refiners and importers of gasoline and diesel will be required to purchase credits from the Cap and Trade credit market to offset the GHG emissions of all California motor vehicles in proportion to the amount of fuels they sell.

The Cap and Trade credit market is a separate credit market from the LCFS credit market. Credit purchase costs from both markets will be reflected in gasoline and diesel prices.

Cap and Trade credits will be purchased in auctions conducted by ARB. The reserve or minimum price for credits effective 2012 will be $10/MT (metric ton), increasing by 5 percent annually plus inflation[25].

ARB has also established an allowance reserve market to limit credit price volatility and will withhold 4 percent of total credits for the reserve to make available through auction.

The maximum price for Cap and Trade credits purchased out of the three tiers of the Allowance Reserve will average $45/MT, increasing by 5 percent annually plus inflation[26].

1. Estimated Average Price of Cap and Trade Credits Table 3 shows the effects of increasing reserve credit prices and Allowance Reserve credit prices by 5 percent annually. A conservative estimate of the average future Cap and Trade credit price is the average of the two prices. Table 3 shows that by 2020, the average of the reserve price and maximum average Allowance Reserve price will be $40.63/MT.

Table 3. Estimated Average Price of Cap and Trade Credits[27]

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Minimum Price	$10.00	$10.50	$11.03	$11.58	$12.16	$12.76	$13.40	$14.07	$14.77
Price Cap[28]	$45.00	$47.25	$49.61	$52.09	$54.70	$57.43	$60.30	$63.32	$66.49
Average Price	$27.50	$28.88	$30.32	$31.83	$33.43	$35.10	$36.85	$38.70	$40.63

2. Estimated Cap and Trade Wholesale Diesel Price Impacts The cost of Cap and Trade credits will be reflected in the wholesale price of fuel in direct proportion to the carbon intensity of the specific fuel.

Table 4 shows the impact on wholesale diesel prices of the cost of the Cap and Trade rule requiring refiners to purchase credits to offset the GHG emissions of California motor vehicles.

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[25] Subchapter 10 Climate Change, Article 5, Title 17, California Code of Regulations § 95911. Format for Auction of California GHG Allowances.
[26] Ibid. § 95913. Sale of Allowances from the Allowance Price Containment Reserve.
[27] Dollars/MT
[28] Average Allowance Reserve Cap

Table 4 shows that the cost of this Cap and Trade rule would raise the wholesale cost of diesel by $0.42/gallon by 2020.

Table 4. Cap and Trade Wholesale Diesel Price Impacts[29]

Price impacts	2012	2013	2014	2015	2016	2017	2018	2019	2020
Cap and Trade	0	0	0	$0.33	$0.34	$0.36	$0.38	$0.40	$0.42

3. Total LCFS and Cap and Trade Program Costs
Table 5 displays the total program-based annual price impacts of the combined LCFS and Cap and Trade programs. By 2020, the joint wholesale impact of the two programs would be $1.89.

Table 5. Program-Based Diesel Price Impacts

Price impacts	2012	2013	2014	2015	2016	2017	2018	2019	2020
LCFS	$0.06	$0.11	$0.19	$0.41	$0.46	$1.11	$1.20	$1.31	$1.47
Cap and Trade	0	0	0	$0.33	$0.34	$0.36	$0.38	$0.40	$0.42
Net Program Costs	$0.34	$0.40	$0.50	$0.74	$0.80	$1.47	$1.57	$1.71	$1.89

4. Impact of Combined Program Costs on Wholesale Diesel Prices Table 6 displays the impact of the combined program costs on wholesale diesel prices. The base forecast is the CEC's high price forecast. The net wholesale price is the sum of the combined program impacts and the base case, not including taxes. By 2020, the wholesale price of diesel would be $5.37.

Table 6. Impact of Combined Program Costs on Wholesale Diesel Prices

Price impacts	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Forecast[30]	$3.04	$3.17	$3.30	$3.39	$3.42	$3.45	$3.47	$3.48	$3.48
Net Program Costs	$0.34	$0.40	$0.50	$0.74	$0.80	$1.47	$1.57	$1.71	$1.89
Total Price, ex tax[31]	$3.10	$3.26	$3.47	$4.13	$4.22	$4.91	$5.04	$5.18	$5.37

5. Program-Based Retail Diesel Price Impacts Table 7 displays the retail impacts of the combined LCFS and Cap and Trade costs. The retail impact is the difference between the retail CEC base price forecast and the retail price forecast that includes program costs. Retail prices are calculated using current federal, state and local tax rates[32].

Table 7 shows that the retail impact of the combined LCFS and Cap and Trade programs will increase retail diesel prices by $2.22/gallon by 2020, increasing the retail cost of diesel by 50 percent to $6.69/gallon.

[29] The carbon intensity of diesel is 0.43 MT CO2/barrel. See 40 CFR Parts 86, 87, 89 et al. Mandatory Reporting of Greenhouse Gases; Final Rule. The diesel CI multiplied by the average carbon credit price and divided by 42 gallon/barrel gives the per-gallon cost.
[30] CEC High Oil Price Diesel Price Forecast, Ex Tax
[31] Sum of forecast and total program price increment
[32] Includes 24.4 cpg federal excise tax, 13 cpg state excise tax, 2 cpg state UST fee, 9.12% state tax and 8.11% local tax.

Table 7. Program-Based Retail Diesel Price Impacts[33]

Price impacts	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Retail Price	$3.96	$4.11	$4.26	$4.37	$4.41	$4.44	$4.46	$4.47	$4.48
Program Retail Price	$4.03	$4.21	$4.46	$5.24	$5.35	$6.15	$6.31	$6.47	$6.69
Retail Impact[34]	$0.07	$0.11	$0.20	$0.87	$0.94	$1.72	$1.85	$2.00	$2.22
Percent Increase	2%	3%	5%	20%	21%	39%	41%	45%	50%

E. Implications of Differences between Wholesale and Retail Impacts The 2020 retail impacts of the combined programs are $2.22, 17 percent greater than the 2020 wholesale impacts of the combined programs which are $1.89.

The reason for this difference is that the ARB programs increase refiners' costs of fuels and these additional costs are taxed. This significantly magnifies ARB program costs to the public.

There would be a number of beneficial effects if ARB's LCFS and Cap and Trade program costs were imposed in the form of posted, tax-exempt, per-gallon regulatory fees, in the same manner that other state and federal fees and excise taxes are currently posted and imposed.

It would prevent these regulatory costs from being included in refiners' fuels costs and thereby being amplified in their impact by being themselves taxed.

Tax-exempt surcharges would also avoid the competitive effects created by differences in companies' capacity to absorb program costs without engaging in measures that might adversely affect California fuels markets.

Requiring that ARB LCFS and Cap and Trade program costs be imposed in the form of tax-exempt surcharges would also create greater transparency for the public and Legislature regarding the costs of ARB GHG reduction programs, especially as revenues from those programs are being considered for future spending.

[33] $/gallon.
[34] Retail price including program costs less retail price without program costs.

V. Economic Impacts of Retail Diesel Price Increases

It is beyond the limited scope of this report to identify all the economic impacts that would be associated with a California-only $2.22 per gallon increase in diesel costs. However, it is possible to estimate the effects of such a cost increase on containerized imports and on the logistics industry, which together are important drivers of the state's economy.

A. Containerized Imports Landed in California

The San Pedro Bay ports of Long Beach and Los Angeles are vital engines of the state's and the nation's economies. In 2011, more than $251 billion in containerized trade landed at these two ports. When the rest of California's ports are included, containerized imports in 2011 were worth $281 Billion.

Containerized imports bring benefits to every state in the U.S. through the generation of jobs, income, and tax revenue.

The current recession has significantly reduced the volume of containerized imports landed in California ports. From 2008 to 2009, the total value of containerized imports landed in the San Pablo Bay ports fell by 18 percent.

Containerized import levels have yet to fully recover. A recent study by The Tioga Group, Inc. and IHS Global Insight for the Ports of Long Beach and Los Angeles concluded that recovery would be slow and without the sharp rebound that has characterized some previous recessions[35].

According to the study, the current recession set back containerized imports six to seven years. Because of this set back, imports are not expected to regain their 2006 levels until 2014. Future growth has also been slowed. Between 2010 and 2020, containerized imports are now projected to grow by 5.5 percent annually.

B. Effect of Diesel Cost Increases on Containerized Imports

An authoritative study conducted by Leachman & Associates for the Southern California Association of Governments (SCAG) estimated that a $100 container fee on imports through the San Pedro Bay ports would, in the short-run, result in a 10 percent drop in total containerized import volumes. The long-run impact of such a fee would be a 23 percent decrease in total containerized import volumes. Most of the diverted volume would move to the Puget Sound and Canadian West Coast ports[36].

A Panama Canal scenario examined in the Leachman study included assessing the impact of the current Panama Canal expansion project. The Canal

[35] San Pedro Bay Container Forecast Update. The Tioga Group, Inc. & IHS Global Insight, Report prepared for: The Ports of Long Beach & Los Angeles, July 2009.
[36] Port and Modal Elasticity Study, Phase II, Robert C. Leachman, Leachman & Associates LLC for the Southern California Association of Governments, September 7, 2010.

expansion project will double the capacity of the canal by 2014, by allowing more and larger ships to transit.

In the Panama Canal scenario, all-water steamship rates via the Panama Canal were lowered by 10%, a new domestic intermodal rail terminal at the Port of Tacoma that opened in 2009 was included, and increased crew-shifts at Oakland and Pacific Northwest rail terminals were assumed.

In the Panama Canal scenario, total imports via San Pedro Bay fell sharply with the imposition of container fees. For a $100 container fee, total imports fell by about 15 percent in the short-run and 25 percent in the long-run.

1. Diesel Cost Impacts on Drayage Rates An increase in diesel costs would have an effect equivalent to the imposition of a container fee by increasing the fuel surcharge that trucking companies use to offset the increased costs of fuel.

The trucking fuel surcharge is based upon EIA's weekly California retail diesel price index. The fuel surcharge rate increases by 1 percentage point for every $0.10 increase in the price of diesel fuel. A $2.22 Increase in the retail price of diesel would increase the fuel surcharge rate by 22 percentage points.

The fuel surcharge is levied against the total container rate. The movement weighted average drayage rate from San Pablo Bay ports is $387.89[37]. This rate includes a 31 percent fuel surcharge and local clean truck fees.

Using the values from the SCAG Panama Canal scenario analysis, a 22 percentage point increase in the fuel surcharge rate would add $65.25 to the average dray and reduce containerized imports by 9.8 percent in the short run and 16.3 percent in the long run.

2. Economic Benefits of Containerized Imports In 2007, the Ports of Long Beach and Los Angeles and the Alameda Corridor Transportation Authority commissioned a comprehensive study by BST Associates to estimate the economic benefits throughout the United States of containerized trade moving through the two ports[38].

The BST study estimated the trade value, by state, of containerized cargo moving through the Ports. The estimates were based on data from the Port Import Export Reporting Service, the Department of Commerce, the Bureau of Labor Statistics and other sources.

[37] Trip segment movement-based weighted average cost, Trip segment movements from *"Container Diversion and Economic Impact Study: Effects of Higher Drayage Costs at San Pedro Bay Ports," Prepared for the Port of Long Beach and the Port of Los Angeles by Moffatt and Nichol and BST Associates, September 2007*, p. 17; Segment drayage costs from confidential motor carrier survey.

[38] Estimate based upon multipliers in Trade Impact Study, Final Report Prepared for Port Of Los Angeles, Port Of Long Beach, Alameda Corridor Transportation Authority. BST Associates, March 2007.

California's share of the benefits of containerized imports was 23.6 percent, making California's 2011 share of containerized imports approximately $66.4 billion.

The BST study also developed factors, based upon the RIMS Regional Input-Output Modeling System, which allowed the state-specific calculation of total domestic product value, income, employment and taxes[39].

Applying the BST RIMS factors, the total domestic product value to California in 2011 from its share of containerized imports was $105.6 billion. This value represents the total amount of increased direct spending, the value of increased indirect spending that occurs when direct spending is received by suppliers and service providers, plus induced increased spending by households of employees with additional income.

The total income associated with 2011 California imports was $33.4 billion. This represents increases in wages and salaries of persons employed by the various industry sectors affected by import trade.

Total employment associated with 2011 containerized imports was 951,152 jobs.

Estimated state and local taxes associated with containerized imports, including sales and property taxes, was $8.1 billion.

3. Losses of Container Imports Due to Diesel Price Increases Economic losses associated with containerized imports due to diesel price increases would begin in 2015, when the first significant diesel price increases from the combined effect of the LCFS and Cap and Trade programs appear.

Table 8 shows projected annual and cumulative economic effects of reduced containerized imports caused by increased diesel prices. The projections are based upon program-based increases in retail diesel prices, the effect of those increases on drayage costs, short and long-run impacts and projected import growth.

Table 8. Annual and Cumulative Economic Impacts of Lost Containerized Imports (Billion Dollars)

	2015	2016	2017	2018	2019	2020	Cumulative
Domestic Product	$5.2	$5.8	$11.1	$12.8	$15.4	$18.2	$68.5
Income	$1.7	$1.8	$3.5	$4.1	$4.9	$5.8	$21.7
Employment	47,101	52,169	99,650	115,606	138,512	153,416	616,922
Tax Revenues	$0.4	$0.4	$0.9	$1.0	$1.2	$1.4	$5.3

[39] The RIMS model, developed by the U.S. Bureau of Economic Analysis, is used to estimate how the economy responds to changes in economic activity. It is one of two basic economic models used to measure economic impacts, the other being IMPLAN. They yield similar results because IMPLAN is based upon RIMS.

As Table 8 shows, losses that begin in 2015 increase annually through 2020.

The magnitude of projected cumulative losses is quite large. Cumulative losses for total domestic product, income, employment and tax revenues are equivalent to 65 percent of 2011 totals.

Another way to compare the magnitude of projected cumulative job losses is versus California job losses due to the current recession when, between 2007 and 2010, 1,304,600 jobs were lost. The projected loss of 616,922 jobs, solely due to possible ARB program-based retail diesel price increases, would be nearly half the state's total recession-related job losses[40].

The timing of these job losses, beginning in 2015 around the time the California economy is projected to be recovering from the current recession, could not be worse. They raise the possibility that the adverse economic impacts of ARB's program-based diesel fuel cost increases could set back California's economic recovery for many years.

B. Effect of Cost Increases on the State's Logistics Industry
Increases in the price of diesel will also have a direct impact on the state's economy, especially its logistics industry.

The logistics industry is made up of a variety of industry groups responsible for the shipping, receiving, processing, and storage of goods. In addition to its importance as a major source of employment within the state, the logistics industry plays a critical role in other economic activity in California, as most goods-producing industries rely on it to transport raw materials and finished goods.

The state domestic product attributable to the logistics industry is $189.6 billion or 13.9 percent of state domestic product. The industry employs 2,095,624 people, 12.7 percent of all employment. The logistics industry also provides $165.6 billion or 13.1 percent of state wide earned income and $24.4 billion or 23.5 percent of all state and local tax and fee revenues [41].

While a reduction in containerized imports would harm the state's logistics industry, increased fuel prices would also impact that industry's other activities. Included in such activities would be transporting the $97 billion in non-containerized imports that land at California's ports, the $122 billion of California-originated exports and the shipping, receiving, processing, and storing of domestic-originated goods produced and consumed by California consumers and businesses.

[40] Historical Annual Average Data, California Employment Development Department.
[41] Multi-County Goods Movement Action Plan, Technical Memorandum 5a – Economic Benefits and Costs Of Growth In Goods Movement, Los Angeles County Metropolitan Transportation Authority, June 2007, Page E-2.

1. Competitive Effects of Cost Increases The ARB programs will increase California fuel prices, only. Therefore, logistics companies that can avoid the impact of more expensive California diesel prices will have a competitive advantage over companies that cannot.

a. Effects on California Trucking Companies Out-of-state trucking companies will fuel as much as possible in Nevada and Arizona to gain a competitive advantage over in-state firms.

Trucks based outside of California now all use computer-based devices that help avoid California diesel costs by telling drivers when and how much to fuel in California.

This cost-avoidance capability in combination with two 200 gallon fuel tanks gives newer out-of-state trucks a 3200 mile range and would place California-based logistics companies at a marked disadvantage in the competition to provide in-state services.

These large cost advantages could allow out-of-state companies to readily strip away the California logistics industry's key commercial transportation business, especially along the state's central I-5 and US 99 trade corridors.

b. Effects on Warehouse Economics Diesel cost differences will also cause warehouses to reevaluate their California locations. Over the past decade, the warehouse industry has restructured and established a new class of mega-distribution centers. Previously the industry had favored an infrastructure of many small distribution centers, each located close to customers. Many of these mega-distribution centers are located in Southern California.

The weakness of such mega distribution centers is their longer delivery distances[42]. Long delivery distances magnify the impact of diesel price increases on the costs of delivery and tip the balance back toward more, smaller distribution centers located closer to customers. Some national distribution centers that serve California and neighboring states may find it in their interest to relocate out of California and into neighboring states.

A $2.33/gallon[43] difference in diesel costs would provide an ample financial incentive for out-of-state logistics companies to move logistics capacity out of California and into Nevada and Arizona.

c. The Potential for Private Fuel Imports into California Alternatively, California logistics companies struggling to compete may choose to privately import diesel fuel from Nevada and Arizona for their own accounts. The

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[42] How Will Higher Fuel Costs Impact the U.S. Warehouse/Distribution Markets? ProLogis Research Insights, *Summer 2010*

[43] Includes 11 cpg higher California fuel taxes vs. neighboring states. See Appendix F.

transportation cost, about $0.05/gallon, would be trivial compared to the $2.33/ gallon cost difference.

Independent fuel marketers already regularly offer to construct fuel storage systems in exchange for contracts to deliver fuels at the refinery price. It would be easy for those contracts to be tied instead to transportation services from Arizona and Nevada fuel terminals.

Private importers would not be subject to the LCFS or Cap and Trade regulations because they would not be offering their imports for sale.

Significant quantities of private imports could undermine the health-oriented benefits associated with California-specification diesel fuels.

2. Logistics Industry Provides a Pathway to the Middle Class Job losses in the logistics industry have a social impact that is not typically reflected in the calculus of economic impacts. The logistics industry provides important blue collar employment pathways for workers to enter the state's middle class.

Logistics industry jobs especially provide critical employment opportunities for the 41 percent of Californians over the age of 25 who have a high school education or less[44].

There are few educational training barriers to beginning employment, yet the annual salaries offered are significantly higher than those for other non-professional, non-blue collar jobs[45].

The loss of these opportunities would have a particularly detrimental impact on those Californians who have been most severely disadvantaged by the current recession.

[44] 2010 Census.
[45] See Appendix G for details on Blue Collar Job salary comparisons and educational attainment of citizens 25 years and over.

VI. Renewable Fuels Required for LCFS Feasibility

The feasibility of the LCFS program is dependent on whether regulated parties will have access to specific renewable fuels in the necessary quantities and qualities.

The ARB has created a number of scenarios that in its words are "feasible pathways" for compliance. These scenarios include assertions about how fuel suppliers could achieve compliance.

This section argues that the fuels needed for diesel compliance will either not be usable in the quantities claimed by ARB or simply not available.

CTA analysis of when the LCFS program is expected to become infeasible because of an insufficiency of both gasoline and diesel credits is presented in Section VII. LCFS Non-Compliance and Its Potential Consequences.

The renewable fuels critical to lowering the average diesel CI are biodiesel and renewable diesel, including cellulosic renewable diesel. What follows is a discussion of the issues associated with each fuel in relation to ARB's assertions about how that fuel will be able to contribute to LCFS compliance.

A. Biodiesel

In ARB's compliance scenarios, biodiesel blended with petroleum-based diesel is a critical element for the success of the LCFS. ARB asserts that regulated parties will blend increasing percentages of biodiesel into conventional diesel, with blend percentages reaching 10 percent by 2015 and 20 percent by 2017.

1. Biodiesel Production Biodiesel can be manufactured from almost any plant oil or animal fat. It can be blended with petroleum-based diesel or used in straight unblended form. Biodiesel fuel blends are designated as "BX" where "X" is the percent biodiesel, by volume, in the blended fuel.

The biodiesel manufacturing process converts oils and fats into fatty acid methyl esters (FAME). The conversion process is referred to as transesterification.

Economics affect the choice of plant feedstocks used to make biodiesel. Plant feedstocks that can be used include the food-based feedstocks of soybean, peanut, canola, cottonseed and corn oil. Most of the world's production of biodiesel comes from plant oils such as soybean, rapeseed (canola), and palm oil. About 90 percent of U.S. biodiesel is made from soybean oil and most is manufactured in the Mid-West.

Biodiesel can also be made from animal fats, such as used cooking oil (also known as yellow grease) and inedible tallow. Since these feedstocks are wastes, their CI rating is very low, unlike for crop-based feedstocks. However, waste animal fats are limited in availability and currently used for livestock and poultry feed.

a. Biodiesel Production Capacity According to U.S. EPA, U.S. biodiesel production *capacity* is currently about 2.1 billion gallons. However, that estimated capacity has not, to date, been fully utilized.

The RFS2 requirement for biodiesel is 1.28 billion gallons in 2013, equivalent to about 1.1 percent. Any greater future requirements are subject to EPA review.

The largest amount of biodiesel ever consumed in the U.S. was 358 million gallons, in 2007[46]. At that time, a $1.00/gallon federal blender's tax credit was in place. Any gallon of biodiesel, for domestic consumption or export, which was blended with diesel, was eligible for that tax credit. The tax credit expired in 2011.

ARB's recent review determined that California nameplate biodiesel manufacturing capacity is about 70 million gallons. Despite the nameplate capacity, Table 9 shows that California biodiesel consumption had fallen to 5.4 million gallons in 2010[47].

Low biodiesel consumption may be due, in part, to the relatively high cost of biodiesel. During the last six months of 2011, the Chicago price of B100 (pure biodiesel) averaged $5.57/gallon[48] compared to the average California conventional diesel price for that period of $3.34/gallon[49], a $2.23/gallon difference.

Another reason could be that California refiners do not have the necessary infrastructure for the transport, storage and blending of biodiesel and have therefore chosen to comply with RFS2 requirements in locations where the supply of biodiesel is associated with the necessary blending and distribution infrastructure.

Table 9. California Biodiesel Consumption 2006-2010[50]

Year	2006	2007	2008	2009	2010
Biodiesel consumption (million gallons)	19.61	17.459	11.702	6.921	5.398
Average content (percent)	0.53	0.46	0.34	0.22	0.16

The CEC's California biodiesel demand forecast envisions future biodiesel consumption to be supplied exclusively from in-state sources of biodiesel production.

[46] http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-09_workshop/presentations, /06, Gordon Schremp Low Carbon Fuel Standard Analysis, pdf
[47] California Board of Equalization
[48] OPIS B100 Prices, December 17, 2011.
[49] EIA Gasoline and Diesel Update, ex tax.
[50] Low Carbon Fuel Standard 2011 Program Review Report, Final Draft December 8, 2011, page 79.

That forecast, reproduced here in Table 10, shows biodiesel volumes never going above 64 million gallons per year, an overall diesel proportion of approximately 1.6 percent.

Table 10. CEC Biodiesel Demand: High Price Case (million gallons/year)

2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
52.7	62.7	61.8	62.9	63.8	63.6	63.2	63.1	62.8	62.2

b. Biodiesel Availability As regards the availability of biodiesel, the currently permitted 5 percent blend would require 170 million gallons of biodiesel in California in 2012, almost 5 times the volume of 2012 RFS2 requirements.

The 20 percent blend level ARB scenarios envision would require California biodiesel usage of approximately 600 million gallons per year, almost 30 percent of U.S. production capacity.

The limited amount of in-state biodiesel production means that additional amounts of biodiesel needed for LCFS compliance would have to be imported from the Midwest, where the majority of production is located.

2. Biodiesel Blend Limits In ARB's compliance scenarios, ARB asserts that regulated parties will blend increasing percentages of biodiesel into conventional diesel, with blend percentages reaching 10 percent by 2015 and 20 percent by 2017.

A problem with this assertion is that biodiesel blends in excess of 5 percent create engine warranty and fuel distribution problems. Therefore, the majority of diesel vehicles on the road could not use higher biodiesel content blends even if they were available, because they are not certified to use them. Moreover, there is no federal obligation on manufacturers to produce engines that can use higher biodiesel-content blends.

Future consumption of higher biodiesel-content diesel would be limited to a smaller subset of newer vehicles with certified engines. In addition, such higher biodiesel content blends would require their own separate fueling infrastructure to ensure that other vehicle owners would not inadvertently use a potentially incorrect fuel.

A separate consideration is that biodiesel blends in excess of 5 percent by volume create higher air pollution in the form of oxides of nitrogen (NOX). Widespread implementation of higher blend percentages would depend on the nature of the mitigation options developed to address that concern.

For these reasons, it is not plausible to assert that biodiesel would be blended with diesel at the percentages and according to the schedule claimed by ARB.

3. The Food-Energy Conflict The dependence of biodiesel on food-based feedstocks places limits on potential future production of biodiesel from those feedstocks. In part this reflects a public concern that energy demand for biodiesel will increase competition for food-based feedstocks with a resulting increase in both fuel and food prices. This competition for the same feedstocks and their relatively low agricultural yields limits the "scalability" of food-based biodiesel production that is expected to discourage future investment in biodiesel manufacturing capacity[51].

A real world example of a food-energy conflict illustrates the issue. The high price of sugar has induced Brazilian cane sugar producers to reduce the production of Brazilian cane sugar ethanol in favor of sugar production.

The resulting domestic ethanol shortage has caused the Brazilian government to reduce the legally required ethanol content of Brazilian gasoline from 25 percent to 18 percent. Lower domestic ethanol availability has naturally reduced the volumes of Brazilian ethanol available for export.

To meet its domestic transportation requirements, Brazil has been forced to import relatively inexpensive Midwestern corn-based ethanol. At the same time, Brazilian ethanol exports have sold, when available, at an average $1.21/gallon premium[52,53].

4. Perverse GHG Impacts of the LCFS The Brazilian example also illustrates a perverse potential outcome of the LCFS that runs counter to the entire effort to reduce GHG emissions; namely, that the additional GHG emissions associated with shipping Brazilian ethanol to California and then shipping Mid-western ethanol to Brazil would increase GHG emissions outside California.

It also points out that any import of low-CI fuels into California to meet the LCFS will increase GHG emissions elsewhere because those fuels will not be available in their location of origin. Thus, California's GHG benefits would be achieved at the expense of the states where the low-CI fuel would be manufactured.

B. Renewable Diesel

In ARB's compliance scenarios, renewable diesel is expected to replace some petroleum diesel on a gallon for gallon basis. Renewable diesel is known as a "drop-in" fuel because it can be substituted for diesel fuel with no adverse consequences

[51] "What matters in biofuels and where are we?" Vinod Khosla, January 27, 2011.
[52] "Recent Trends for Petroleum, Electricity and Renewables," Western States Coordination Meeting, January 19, 2012, Gordon Schremp, Ryan Eggers, Fuels and Transportation Division, California Energy Commission
[53] The premium reflects Brazilian ethanol's status as an advanced biofuel under RFS2. As an advanced biofuel, sugar cane ethanol competes with biodiesel to meet the RFS2 advanced biofuel requirement. Corn-based ethanol, while more readily available via domestic sources, does not qualify as an advanced biofuel.

1. Renewable Diesel Production Renewable diesel is manufactured by treating vegetable oils and animal fats with hydrogen, a process known as hydrogenation. The conversion process is called the Fatty Acids to Hydrocarbon (FAHC) process. The FAHC process is a more costly process than that used to produce FAME biodiesel.

Renewable diesel has a chemical structure that is identical to petroleum-based diesel. This makes it is fungible with petroleum-based diesel and potentially allows it to be comingled in the same pipelines and facilities.

In addition to its fungibility, renewable diesel has a number of other advantages over biodiesel:

- Renewable diesel has a superior emission profile and its combustion results in reduced particulate, NOx, hydrocarbon and CO emissions.
- Renewable diesel has a lower sulfur content than petroleum diesel so its combustion produces lower SOx emissions.
- Unlike biodiesel, the production of renewable diesel does not produce a glycerin co-product that must be separated.
- Renewable diesel has a lower cloud point than conventional biodiesel, giving it better low-temperature operability and allowing its use in colder climates without gelling or clogging of fuel filters.
- There are no inherent limits on the use of renewable diesel as a direct substitute for petroleum diesel in diesel engines.
- Renewable diesel produced from waste animal fats has a very low carbon intensity and is classified under RFS2 as an advanced renewable fuel.

EISA classifies “renewable diesel” as a “biomass-based diesel” and requires that all “biomass-based diesel” above 5 percent be labeled. The result is that pipelines have not allowed renewable diesel above 5 percent concentrations in the fungible diesel system, a limitation that adversely affects the economics of renewable diesel.

While renewable diesel offers many potential advantages compared to biodiesel, the same uneasy competition between feedstocks grown for food and feedstocks grown for fuel can be cited for renewable diesel made from edible oils. The result is that efforts to produce renewable diesel have focused on non-food feedstocks such as animal fat and algae.

Algae are considered to be an ideal feedstock for renewable diesel and other renewable fuels. Algae can produce up to 300 times more oil per acre than conventional crops, have a short harvesting cycle that permits many harvests per year, and can also be grown on land that is not suitable for other established crops.

However, the high up-front investment of algae-to-biofuels facilities is seen by many as a major obstacle to the success of this technology. A number of studies have supported this viewpoint suggesting that unless new, cheaper ways of harnessing algae for biofuels production are found, their great technical potential may not become economically accessible for transportation fuels.

A recent example of significant renewable diesel purchase occurred in December 2011. Dynamic Fuels, a joint venture between Tyson Foods, Inc. and Syntroleum Corp. announced it was awarded a contract to supply the U.S. Navy with 450,000 gallons of renewable fuels, consisting of 100,000 gallons of jet fuel and 350,000 gallons of marine diesel.

The fuel was manufactured in Dynamic Fuels' Louisiana manufacturing plant from tallow supplied by Tyson Foods. The estimated price was $26/gallon, perhaps a reasonable price for a test fuel for the U.S. Navy but outside the range of commercial viability[54].

The purchase was part of the Department of Defense program: Blueprint for a Secure Energy Future. The program directs the Departments of Agriculture, Energy, and Military Services to work together to advance a domestic industry capable of producing drop-in biofuel substitutes for diesel and jet fuel.

A 2010 Navy purchase of biofuel from algae to be used in military tests is reported to have cost $424 per gallon. In 2011, purchases of other biofuels averaged better than $25 per gallon[55].

The various cost and feedstock-related issues associated with renewable diesel have shifted the focus to developing cellulosic fuels made from the cellulosic portions of biomass.

C. Cellulosic Renewable Diesel

A wide variety of feedstocks can potentially be used for cellulosic biofuel production, including agricultural residues, forestry biomass, and certain renewable portions of municipal solid waste, construction and demolition waste and energy crops[56].

Cellulosic feedstocks, however, are more difficult and costly to convert into transportation fuels because of the complex chemical structure of cellulosic material.

1. Production Issues There are a number of candidate cellulosic production technologies under consideration for investment. Those technologies and the various steps involved in the processes that produce finished fuel are typically tied to the specific feedstocks that will be employed.

[54] http://www.federaltimes.com/article/20111206/FACILITIES03/112060301/
[55] http://deltafarmpress.com/blog/though-costly-military-s-utilization-biofuels-represents-step-forward
[56] As defined in EISA, cellulosic biofuel means renewable fuel produced from any cellulose, hemicellulose, or lignin that is derived from renewable biomass and that has lifecycle greenhouse gas emissions, as determined by the EPA, that are at least 60 percent less than the baseline lifecycle greenhouse gas emissions.

This is because investment in production facilities is sensitive to the long-term availability of feedstocks, their costs, including the cost of collection, and the costs of other intermediate steps in the production process.

Thus, the manufacturing facilities for producing finished cellulosic fuels will be located near long-term feedstock sources. A transportation structure will be needed to move the finished fuel to a final distribution point.

There are currently no cellulosic biofuel manufacturing plants in California although an industry could develop once all technical and economic issues were resolved. EPA estimates that California has sufficient forestry and urban waste to produce up to 450 million gallons per year of cellulosic fuels from locations in Orange, Butte, San Joaquin and Siskiyou counties. However, no California projects have been announced.

From a national perspective the development of cellulosic fuels in general and cellulosic diesel, in particular, has not kept pace with expectations. The limited number of "commercial scale" facilities and the extremely low volume of fuel, if any, supplied for transportation purposes reflect the fact that the industry is still in its early "proof of concept" and optimization stages.

The main focus at current cellulosic fuel facilities is research and development, not commercial production. Most current facilities only operate intermittently for the purpose of demonstrating that the technologies can be used to produce transportation fuels.

This is supported by EPA's history of revising cellulosic diesel requirements and issuing year-end credits for compliance.

The industry as a whole is still working to increase efficiency, improve yields, reduce costs and prove to the public, as well as investors, that cellulosic biofuel is technologically and economically feasible.

The current recession is making this process more difficult as the capital funding environment has become particularly risk-averse, especially for first commercial units that are first-of-a-kind technology[57].

2. National Research Council Report A 2011 Report by the National Research Council examined the requirements of the RFS2 program and concluded that it was uncertain whether and how the mandate for cellulosic biofuels would be met[58,59].

[57] "What matters in Biofuels & where are we?" Jan 27, 2011, Vinod Khosla.

[58] Renewable Fuel Standard: Potential Economic and Environmental Effects of U.S. Biofuel Policy, National Research Council, 2011.

[59] The study was sponsored by the U.S. Department of Agriculture, U.S. Department of Energy, and U.S. Environmental Protection Agency.

The NRC noted that there were no commercially viable bio-refineries in existence for converting cellulosic biomass to fuel. It stated that the capacity to meet the renewable fuel mandate for cellulosic biofuels would not be available unless the production process was unexpectedly improved, technologies scaled up and commercial-scale demonstrations conducted in the next few years.

The NRC also remarked that policy uncertainties and the high costs of production might deter investors from aggressive deployment, even though the government guarantees a market for cellulosic biofuels up to the level of the RFS2 consumption mandate, regardless of price.

The NRC stated that a key barrier to achieving RFS2 goals was the high cost of producing cellulosic biofuels compared to petroleum-based fuels and the large capital investments required to put billions of gallons of production capacity in place.

3. Current Status There is a great deal of activity and support directed toward development of a food-independent, biomass-based, reduced-carbon cellulosic fuel industry that will be competitive with petroleum-based fuels.

Progress in ramping up cellulosic fuel production will be a function of investment, resolution of technology options, and funding. However, the development trajectory of the cellulosic fuels industry is uncertain.

EPA has annually reduced its forecasts for cellulosic diesel availability. Refiners have complied with the reduced requirements by purchasing RINs issued by EPA for that specific purpose.

EPA's actions support the conclusion that there is actually no cellulosic diesel fuel currently being produced for transportation purposes. It is not clear when in the future there will be a viable cellulosic transportation fuel industry.

D. Assumptions Regarding Availability of Lower-CI Gasoline

One of the most significant compliance challenges to the LCFS is on the gasoline side, which, as noted earlier, is expected to provide the excess credits needed to compensate for diesel deficiencies as well as offset its own CI deficit.

While problems on the gasoline side are significant, detailing them is beyond the scope of this paper[60]. Despite that, for the purposes of this discussion and because they affect the overall feasibility of the program, they are here briefly summarized.

[60] A detailed analysis is available in Review of the CARB Staff Analysis of "Illustrative" Low Carbon Fuel Standard (LCFS) Compliance Scenarios, prepared by Sierra Research, Inc for the Western States Petroleum Association. February 20, 2012.

ARB's existing estimates concerning compliance on the gasoline side are flawed due to unrealistic assertions regarding fuel volumes and the timing of fuel availabilities, specifically:

- ARB's assertions that future ethanol CI values will be substantially lower and extend the period during which Midwestern ethanol will be useful for generating positive credits. These unsupported assertions have been made so as to offset ethanol's declining credit production utility under annual CI target reductions. In the absence of such claimed CI improvements, regulated parties would have to accelerate their use of lower-CI Brazilian cane sugar ethanol to meet annual targets.
- Unrealistic expectations regarding the California availability of Brazilian cane sugar ethanol imports in volumes which would dwarf historical U.S. import levels and are contradicted by Brazilian and U.S. import forecasts.
- An assertion that the percentage of ethanol allowed to be blended in gasoline will increase to 15 percent. The ethanol composition of gasoline is restricted to 10 percent because many vehicles cannot use higher blends without damaging their emission systems or engines.
- Claims of substantial increases in the consumption of E85[61] despite the absence of sufficient E85-capable flex-fuel vehicles, the absence of a costly E85 dispensing infrastructure, and the likely higher cost of low-CI Brazilian ethanol which would prevent E85 being sold at a discount to gasoline[62].
- Unrealistic expectations regarding the timing and availability of cellulosic ethanol and gasoline production that parallel those on the diesel side and are similarly impacted by the slow pace of the industry's development.

[61] A gasoline substitute composed of 25 percent gasoline and 75 percent ethanol that can only be used in specially manufactured flex-fueled vehicles
[62] Ethanol has roughly one-third lower energy content per unit of volume compared to gasoline, so more fuel is required to travel the same distance.

VII. LCFS Non-Compliance and Its Potential Consequences

The cost analyses developed in this study are predicated upon compliance. However, many observers, including CTA, have concluded that compliance is highly unlikely.

This study has already indicated that diesel additives and substitutes will not be able to offset the diesel credit deficiencies that the annual compliance target will create starting from the beginning of the program.

Additionally, challenges to LCFS on the gasoline side, which under the current structure is expected to provide the excess credits needed to compensate for diesel deficiencies, compound the difficulty for regulated parties in meeting the LCFS.

This section first discusses several non-compliance analyses and the assumptions each organization has used to determine whether and when the LCFS will become infeasible.

This is followed by a discussion of factors that could affect the costs of non-compliance. These factors center around the potential behavior of different institutions in the LCFS credit market including non-obligated parties, regulated parties especially oil companies and the ARB itself.

The conclusion of this section is that the LCFS's certain infeasibility will prompt a tightening of LCFS credit markets and a steep increase in the price of credits. This LCFS credit shortage and price increase will be anticipated and exacerbated by the withholding behavior of speculators that could include non-obligated and regulated parties.

The reactions of oil companies to those increased LCFS credit costs could include actions that increase diesel exports to reduce their requirements to purchase LCFS credits. This would reduce the supply of diesel in the California market and lead to even high price increases.

ARB appears to be woefully unprepared to administer and manage an important credit market that in the view of many informed parties could face challenges as early as 2014.

A. Non-Compliance Analyses

An assessment of the timing of when, precisely, compliance will no longer be possible is dependent upon the assumptions used.

1. Sierra Research Non-Compliance Analysis Sierra Research's analysis determined that non-compliance could occur as early as 2014.

Sierra's compliance analysis was performed using assumptions that the supply of biofuel substitutes for gasoline in California would be equal to EIA's biofuel supply forecasts multiplied by California's proportional share of the total U.S. gasoline and diesel supply.

Using these assumptions, Sierra concluded that LCFS compliance would only be feasible through 2015.

Sierra also found that if ARB's assumptions regarding decreases in the CI values of certain biofuels over time did not occur, credit deficits would occur in 2014.

2. CEC Non-Compliance Analysis The CEC developed three compliance analysis scenarios. The CEC's Case One scenario is the CEC's most conservative scenario in that it used the least comparatively unlikely elements.

For Case One, CEC staff assumed the initial maximum volumes of biofuels available for use in California were the aggregate production capacity of bio-refineries that either had completed or pending registrations. CEC did not consistently use its forecasts in its compliance analysis.

In CEC's Case One scenario:

- Initial bio-refinery production capacities were gradually increased over the forecast period by 5 percent annually through 2015 and then 10 percent annually through 2020.
- Ethanol use did not exceed California's RFS2 proportionate share volume.
- Biodiesel could rise to a level in excess of California's RFS2 proportionate share volume, but not exceed the B10 level through 2015 and not exceed B20 level for 2016 through 2020.
- No cellulosic gasoline or diesel substitutes were included.

CEC's Case One analysis showed that, in the absence of non-obligated party credits, non-compliance could occur in 2015. Including non-obligated party credits, non-compliance would occur in 2017.

3. CTA Non-Compliance Analysis The CTA compliance analysis estimated that companies would be out of compliance on an annual basis by 2015. CTA's key assumptions were that:

- Biodiesel, E85, electricity, LNG and natural gas consumption were consistent with CEC high oil price forecasts[63,64].
- No cellulosic substitutes would be available for gasoline or diesel.
- Ethanol CI would maintain a constant average of 81 CI, a sufficiently low level to permit credit generation through 2020.

[63] CEC high oil price forecasts are associated with greater amounts of alternative fuels demand.
[64] Transportation Energy Forecasts and Analyses for the 2011 Integrated Energy Policy Report, CEC-600-2011-007-SD, August 2011.

The first annual deficit would appear in 2014 but be offset for one year by credits earned through prior years' over-compliance.

B. Factors Influencing Non-Compliance Costs

The actual costs incurred by regulated parties when the LCFS becomes infeasible will be determined by the price and availability of LCFS credits and the effects of LCFS credit costs on fuel prices and supplies. These costs are difficult to forecast but, in the absence of timely ARB intervention, have the potential to reach extremely high levels.

1. Credits Attributed to Non-Obligated Parties A key element in all compliance analyses is the behavior of non-obligated parties. Non-obligated parties are entities providing electricity, compressed natural gas, LNG and California biogas volumes who can earn credits by providing or fueling transportation alternatives.

According to the CEC, credits attributable to non-obligated parties are 11 percent of all positive credits, making them a potentially significant factor in achieving compliance.

However, all compliance scenarios make two assumptions regarding the actions of non-obligated parties in the LCFS credit market. The first assumption is that *all* non-obligated parties act to take possession of their LCFS credits so they can sell them to obligated parties and realize their associated revenues. The second assumption is that non-obligated parties will sell their credits during the year they are earned. Neither assumption is likely to be correct.

In order to take possession of credits non-obligated parties must be able to document related actions and quantities to the ARB. This will require a significant effort by entities, such as cities and counties that provide electric vehicle charging spaces, which may not have the accounting structures to provide such information. Some of these entities may decide that the potential additional revenues would not justify the added accounting costs. This may reduce the number of credits available from non-obligated parties.

The second assumption, that non-obligated parties' credits would be annually sold and included in the net credit balance, is also unlikely to be true. Non-obligated parties will probably retain their credits, expecting them to be valued higher in the future as the credit market tightens. This retention of credits would foster a tighter credit market sooner than actual non-compliance might occur.

Additionally, some institutions may wish to acquire and retire the credits of non-obligated parties in order to influence the behavior of obligated parties. The effect of such retirements would be a further reduction of the actual availability of non-obligated party credits.

Finally, some parties may wish to acquire credits by offering to purchase the right to apply for credits on behalf of specific non-obligated parties. They could offer to relieve those parties of the expense of securing the credits while still realizing some revenue benefits. Such parties could do so for their own accounts or on behalf of regulated parties.

These issues associated with non-obligated parties foreshadow a prospective tightening of credit markets marked by an enhanced interest by obligated parties to secure the credits needed for LCFS compliance.

2. Possible Consequences of LCFS Credit Shortages The ARB's view of the LCFS credit market is based upon on the theoretical notion of well-functioning markets in which the price of credits would be reflected by the balance between the availability of and the demand for credits. The theoretical assumption is that increases in the price of credits will act both to affect the demand for and availability of credits.

However, there is good reason to believe that higher credit prices will *not* result in the timely production of more credits. The processes that result in greater numbers of credits, such as the production of greater amounts of low-CI ethanol, increased E85 sales and increased production of cellulosic fuels, all face significant barriers and inherent delays that will not promptly respond to higher credit prices to make more credits available.

Also, unlike in the Cap and Trade rule, there is no upper limit on the price of LCFS credits. This makes the LCFS credit market a prime target for speculators who would amass credits on the basis of their expectations regarding the infeasibility of the LCFS. Some of those speculators can be expected to be regulated parties.

Speculators will be counting on a slow regulatory response to the eventuality of price spikes. They will expect to be able to realize their profits before trading in the credit market is suspended. Their expectations are encouraged by ARB's undeveloped LCFS market structure and its misplaced confidence regarding the feasibility of the LCFS rule.

a. The Costly Prior Example of California Electricity Restructuring California has had bad experiences with regulatorily-designed markets that didn't perform as expected. The most recent example occurred in connection with the 1995 restructuring of the California electricity industry. That effort, by the California Public Utilities Commission (CPUC), required the state's investor-owned electric utilities to use two different regulatorily-designed markets to meet their customer's electricity requirements.

However, the CPUC markets were ill-conceived. They were readily exploited by out-of-state electricity companies who had acquired California generating assets from the state's electric utilities who had, ironically, been required by the CPUC to sell them.

The electricity crisis of 2000 was the result of those out-of-state companies and other entities creating "shortages" of electricity so that the state's electric utilities had no option but to purchase electricity priced as high as $700/Megawatt-hour compared to a normal cost of $20/Megawatt-hour[65].

Worse, the key regulatory agencies ostensibly responsible for regulating the entities responsible for the crisis, the CPUC and the Federal Energy Regulatory Commission, did not act in a timely or effective way to defuse it.

The result in the end was that California was forced to pay more than $40 billion extra for electricity[66]. That cost is still being absorbed by current electricity customers whose electricity rates are second-highest in the nation.

This history of regulatorily-established markets suggests that California should proceed with great caution regarding ARB-established markets, especially since ARB has no previous experience or qualifications for establishing or overseeing markets.

3. Possible Reactions of Oil Companies to Credit Shortages The high likelihood of credit shortages present California oil companies with a competitive challenge[67]. In the absence of or in anticipation of slow or absent ARB action to intervene in the credit market, which company will be the last to run out of credits?

Companies will differ in their approaches depending on their competitive position and markets they serve. However, they will resort to strategies that make sense from a competitive business perspective rather than out of concern for the public good.

The last companies to run out of credits will be able to produce fuels in compliance with the LCFS. These companies will be in the best position to take advantage of the high fuel prices that will accompany and be provoked by a credit shortage.

Those companies that anticipate running short of credits sooner may act in ways to reduce their overall credit requirements and extend their compliance. One way would be for them to lower their need for positive credits by reducing the overall

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[65] The Legislature implemented the CPUC market design and tried to protect consumers from the possibility of high electricity prices through a retail electricity price freeze, a measure that ultimately proved ineffective.

[66] Weare, Christopher. *The California Electricity Crisis: Causes and Policy Options*. San Francisco: Public Policy Institute of California. ISBN 1-58213-064-7., 2003, p. 3

[67] "The Iron Law of Regulation: Every act of government, no matter what its broader merits or demerits for society at large, creates winners and losers within the competitive sector of the economy." Who Profits: Winners, Losers, and Government Regulation. Robert A. Leone, Basic Books, New York, 1986.

amounts of transportation fuels they sell in California, exporting a portion of the fuels they would ordinarily produce for in-state use.

Refining marginally less fuel for in-state use would marginally curtail in-state supply. This would foster a tightening fuels market and cause fuel prices to increase. Price increases would compensate for those entities' lost profits on foregone California sales.

Such actions would probably focus most on diesel. Diesel accounts for less than 20 percent of oil company refining and marketing profits. Diesel production also only produces negative LCFS credits which must be offset by extra gasoline production credits for compliance. Every gallon less of diesel production would free up gasoline credits and extend the timeframe of company compliance.

Diesel consumption is tied almost exclusively to commercial activity. Its use is relatively inelastic and therefore less likely to decline in the face of price increases, unlike gasoline use, which is more sensitive to price-driven reductions. Diesel prices also have a lower political profile than gasoline prices since most consumers are unaware of their importance.

It is, therefore, highly possible that credit shortages could have a significant and disproportionate effect on diesel prices, an eventuality that could create even more economic damage than the high diesel prices that could result from compliance.

4. LCFS Credit Trading Market Development ARB appears to be woefully unprepared to administer and manage an important credit market that in the view of many informed parties will face challenges as early as 2014.

Given its pending importance, the LCFS credit trading market is in an extremely undeveloped condition. Moreover, ARB's apparent timeframe for credit market development can best be described as unhurried. It appears to reflect ARB's expectation that it will have a long time to develop the credit market and that any compliance problems would not appear until late in the program.

The current trading market system is manual. Although the need for an automated system has been noted and urged by regulated parties, no information on its pace of development or likely time of availability has been issued.

Credit generation and banking are dependent upon the submission of a quarterly report before any credits can be placed into a regulated party's bank. Once credits are banked, the regulated party would be free to sell those credits to other regulated parties.

Credit transactions between parties must be reported using a credit transfer form and approved by the ARB in order to be valid. No credit transaction can take place before ARB confirms credits have been generated. The ARB transaction confirmation or denial process can take as long as five days[68].

ARB is required to publish aggregated transaction information quarterly and monthly. However, quarterly reports published to date, which are far simpler than they will be because they don't yet include transaction information, have not appeared until more than 4 1/2 months after the quarter has ended. This does not speak well of ARB's capability to manage the critical administrative and information requirements of the credit market.

ARB acknowledges that among the products that will be needed for credit market development is a new reporting tool for regulated parties and a central information system. However, these are future products whose development schedule is focused on the "mid-term," a fuzzy ARB term that means "not now."

Future analyses are also expected to inform ARB on whether it would be beneficial for third parties to operate the market and whether to make the market accessible to non-regulated entities.

There are other elements missing from ARB's LCFS credit market. There is no allowance reserve with price limits to control credit price spikes, a mechanism present in the Cap and Trade market. There are also no holding limits on LCFS credits, making it possible for entities to amass and withhold large credit balances in ways that could acutely affect credit market prices. The addition of elements like these would require regulatory amendments and take many months to implement.

ARB has no track record in running a market of any kind; its experience is mainly theoretical. Yet the LCFS market is the most crucial element of the multi-billion dollar LCFS rule.

ARB's desultory progress and limited attention to the credit market raises great concern. The economic damage associated with unmitigated price spikes and the potential responses of regulated parties to credit shortages could be very destructive to California.

C. Conclusions

Should the LCFS prove feasible in accordance with ARB's projections, the cost of compliance would already pose an economic challenge, in the form of significantly increased fuel prices, for businesses operating within the state and for consumers.

[68] Section 95488. Banking, Trading and Purchase of Credits.

Yet multiple factors suggest that compliance with the rule as written will not be feasible. The specter of even higher fuel prices, resulting from the rule's infeasibility prompting a tightening of credit markets, the subsequent reaction of oil companies to those increased costs and the prospects of slow or inadequate ARB action, could be even more damaging to the state's economy.
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VIII. Concerns Regarding ARB's Lack of Preparedness

It is clear to most observers that the LCFS is in trouble because the developments it is counting on to occur seem to have little likelihood of doing so in the time frames the rule requires.

Independent assessments such as those cited here suggest that problems in the form of credit shortages and increased credit prices could appear as early as 2014 and almost certainly by 2015.

In an ideal world, stakeholders, legislators and the people of California might expect that the ARB would be on top of this issue and have a plan to intervene to prevent the potentially catastrophic negative consequences that could occur.

However, for that to be the case, the ARB would have to have demonstrated a better capacity to assess and adjust to reality than it has demonstrated to date.

An example of the ARB's apparent unwillingness to address flaws in its LCFS program was its recently completed *Low Carbon Fuel Standard 2011 Program Review Final Report.*

A. Recently Completed LCFS Program Review

The LCFS regulation requires ARB's Executive Officer to conduct two reviews of the LCFS program in a public process, the first due in January 2012 and the second in January 2015. These reviews are intended to address a broad range of implementation topics and may include recommended amendments to the regulation. The regulation further requires that the ARB convene an Advisory Panel of interested parties to assist in the program review.

An Advisory Panel was convened in 2011 for the 2012 review. It included representatives of the California Energy Commission; the California Public Utilities Commission; fuel providers; storage and distribution infrastructure owner/operators; consumers; engine and vehicle manufacturers; environmental justice organizations; environmental groups; academia; public health; and other stakeholders and government agencies.

Yet the feedback provided by the advisory panel was not reflected in ARB's final report on LCFS implementation.

Although the Advisory Panel found and communicated a number of significant systemic challenges related to LCFS compliance, these issues and their consequences were downplayed in the report. Specific issues raised by the Advisory Panel included:

- The program faces serious challenges to its feasibility because the compliance schedule is too short to achieve the required carbon intensity reductions.

- The only reason that compliance problems have not already emerged is that the combination of extremely low early carbon targets and the current 10 percent ethanol content of gasoline have created a temporary excess of credits.
- ARB's assessment of the program's feasibility hinges on unrealistic staff estimates for:
  - The number of credits likely to be available from the sale of E85.
  - The quantities of cane sugar ethanol likely to be available to California.
  - The quantities of cellulosic fuels likely to be available to California.
  - The "allowable" proportions in which biodiesel may be blended into diesel.
- The Advisory Panel took special issue with ARB staff's "illustrative scenarios" which, although based on events or circumstances that had little likelihood of occurring, purported to show "a variety of ways that regulated parties can comply with the regulation" [69] and were pronounced by ARB staff to be "plausible and feasible."[70]

A particularly disturbing ARB action was its failure to provide an opportunity for the Advisory Board to review its economic analysis, especially its assessment of LCFS price impacts. Given the results of the price-impact analysis in this study it seems clear that ARB is trying to hide the fact that its LCFS rule could have a large negative impact on the economic well-being of the state.

ARB's failure in its final report to seriously consider the issues raised by the advisory panel as well as its attempt to hide the impacts of its rules does not create confidence in ARB's willingness to address in an expedient manner the potential problems that could be associated with non-compliance.

B. Alternative Compliance Mechanisms

One of the issues ARB deferred consideration of in its recent report is alternative compliance mechanisms (ACMs). ACMs have been suggested as a means of allowing regulated parties to comply in the event that it would be otherwise infeasible for a party to meet regulatory requirements[71]. Several approaches have been suggested:

- Reducing the annual CI target to reflect limited supplies of low-carbon fuels.
- Retaining the regulatory requirements regardless of available market supply, but issuing additional credits to head off high credit market prices.
- A combination of the preceding two approaches that would ease the annual requirement while also allowing the issuance and purchase of additional credits to compensate for credit supply limitations.

[69] Low Carbon Fuel Standard 2011 Program Review Report - Final Draft, December 8, 2011, page 16.
[70] Ibid., page 17.
[71] Alternative Compliance Mechanisms, Design Options Discussion, Chris Hessler, AJW, Inc., LCFS Advisory Panel, August 2011.

This third option is the approach used by EPA for the RFS2 regulation. There is both an annual revision of targets and a credit purchase option that allows fuel suppliers to purchase "RIN credits" in lieu of alternative fuels.

The potential issuance of credits raises the issue of how to price those credits. Since the key purpose of the LCFS program is to foster the development of alternative fuel substitutes and transportation alternatives, alternative compliance mechanisms that are less costly will be seen to soften the support for such development.

Some will take the position that a less-costly approach will delay alternatives development and therefore credits need to be priced high enough so as not to undermine alternative fuel development activities.

On the other hand, an argument can be made that the levels of regulatory requirements themselves place an unrealistic set of expectations for production and infrastructure development on an alternative fuels industry that is in a very immature state.

The latter argument suggests that, given the commercial issues the alternatives industry must address, the industry is being developed as quickly as it can attract investment and prove the commercial viability of its production systems.

Moreover, the RFS2 requirements that are revised annually to establish their reasonableness already provide both realistic and sufficient incentives for the development of various transportation alternatives.

The adaptability and market-based character of the RIN system raises the possibility that adapting the RIN system for LCFS compliance might be an option that could be fruitfully explored[72].

However, although such an approach has been suggested, ARB's indefinite deferral of the topic means it will not be considered in a timely way.

C. Current Expectations Regarding ARB Actions

While there are actions that can be taken to address the expected infeasibility of the LCFS, it is unclear whether the ARB is willing to act in a timely manner to adjust its requirements.

There is no significant politically authoritative pressure on the ARB to adjust its course. The ARB has, under AB 32, virtually exclusive authority in this area.

[72] "Using U.S. EPA RINs for CA LCFS Compliance," CARB Compliance & Enforcement Workgroup, December 13, 2007 Meeting, John R. Braeutigam, Valero Energy Corporation.

ARB's reluctance to contemplate infeasibility in the Advisory Committee report is not encouraging. Similarly, the scheduled 2015 review may be too late to avoid some of the unpleasant consequences of widespread and unavoidable non-compliance.

It is possible that the ARB believes that it risks its international standing if it backs off from its rule.

California is holding itself out as a domestic and global example of how governments can take steps to actively address climate change. That is an estimable objective--as long as it is not accomplished via an infeasible program that will impose damaging costs on the California economy.

The difference between the LCFS and previous air quality regulations is that there was a direct relationship between poor air quality and legitimate health concerns and proposed regulatory changes could have an immediate impact on public health.

ARB's climate change-oriented actions will bring no immediate public health benefits and, because California already has an exceptionally low GHG footprint, will make no significant contribution to the reduction of global GHG emissions.

This is all the more reason for ARB's GHG reduction plan to take into consideration the broader impacts its program might have. ARB should reconsider whether the value of being seen an international leader merits imposing significant California-only fuel costs that will significantly disadvantage California businesses and citizens and have a negative impact on the California economy.

As a global leader, California must show itself to be a good example. If its carbon reduction objectives are achieved via smart and careful policy, others will wish to follow suit.

On the other hand, if California gets it wrong by willfully pursuing an infeasible and unaffordable program, others may back away from their own efforts to reduce carbon emissions.

The ARB should not wish to repeat California's failed experiment with electricity restructuring, where other states' efforts were quickly abandoned after the spectacle of California's disastrous experience.

IX. Policy Recommendations

A. Institute Greater Policy Oversight over ARB. There is currently no effective policy oversight over ARB. This may be a key reason why ARB is not particularly responsive to stakeholder concerns.

Despite the formal requirement that ARB consider input from stakeholders, there is no independent institutional framework that assesses the ARB's actions or lack thereof regarding that input.

The most recent example of this lack of responsiveness is ARB's misleading report regarding stakeholder concerns raised during the recent LCFS program review.

This lack of responsiveness suggests that the regulatory requirement for the convening of an advisory panel for a program review is merely window dressing and has no actual value.

ARB's critical planning oversights, its concealment of the projected high diesel costs imposed by the LCFS and Cap and Trade programs and concerns about ARB's potential lack of preparedness to mitigate unchecked credit market shortages raise questions about continuing to support ARB's independent ability under AB 32 to impose significant costs on the California economy.

The Legislature should review this issue and consider oversight options to ensure that the GHG reduction costs imposed by ARB programs are affordable.

C. Improve ARB's Governance Structure. Another source of concern is ARB's governance structure and whether the current structure fosters the diversity of capabilities and views that the effective implementation of its mission requires.

All Board members, other than the chair, are part-time and compensated only for their appearances at meetings. These part-time Board members have no independent analytical support or personal staff.

To familiarize themselves with the issues and decisions ARB faces, its part-time Board members are dependent on staff briefings that take place just prior to public meetings. The briefing books for those meetings are voluminous and cover complex topics which require deliberation and study to understand.

Public meetings dedicated to approving regulatory items consist of staff presentations and public comments limited to three minutes per witness. Interactions between witnesses and Board members, which might be informative, are not encouraged. Written comments are solicited but their fate is unknown.

One way to improve the governance structure of the ARB would be to provide Board members with full-time personal staff and independent analytical support so they can individually play a more prominent, critical role in the debate over policies.

The Legislature should review this issue and consider strengthening the governance structure of the ARB to empower part-time Board members with the analytical resources and support capabilities they require to play a more effective role in policy decisions.

C. Remove Diesel from the LCFS Program. Diesel makes a relatively small contribution to LCFS compliance. This raises the question of whether it makes sense to continue to include diesel in the LCFS program.

Diesel GHG emission reductions that would result from the LCFS are so minor, they account for only 0.15 percent of all recommended GHG reduction measures.

Yet, retaining diesel in the LCFS program raises the prospects of the significant economic damage and the hundreds of thousands of lost jobs that would be caused by $2.22/gallon retail diesel price increases.

The Legislature should review this issue and consider removing diesel from the LCFS program.

D. Require Regulatory Costs be Imposed as Tax-Exempt Surcharges. The Legislature should review and consider requiring that the LCFS and Cap and Trade program costs ARB imposes on refiners be reflected in the retail prices of transportation fuel in the form of tax-exempt, per-gallon surcharges in the same manner that other state and federal fees and excise taxes are currently posted and imposed.

This would prevent these regulatory costs from being included in refiners' fuels costs and thereby being amplified in their impact by being themselves taxed. ARB-imposed diesel costs had a 17 percent higher impact at the retail level compared to if they had been imposed as tax-exempt surcharges.

Imposing program costs in the form of tax-exempt surcharges would also avoid the competitive effects created by differences in companies' capacity to absorb program costs without engaging in extraordinary measures that might adversely affect California fuels markets.

Finally, requiring that ARB LCFS and Cap and Trade program costs be imposed in the form of tax-exempt surcharges would create greater transparency for the public and Legislature regarding the costs of ARB GHG reduction programs, especially as revenues from those programs are considered for future spending.

X. Conclusions

California has embarked upon a GHG policy path that could substantially affect the state's transportation fuels market, elevating diesel fuel prices to a degree that would have far-ranging consequences for various critical sectors of the state's economy.

These price impacts are associated with possible compliance outcomes of the California Air Resources Board's proposed Low Carbon Fuel Standard, in combination with the impacts of ARB's Cap and Trade program.

In the case of a Compliance Outcome, in which the alternative fuels envisioned by the ARB to be used by regulated parties turn out to be available, there will be significant cost consequences from incorporating those alternative fuels into California transportation fuels.

These costs will be added to costs that will be independently imposed by the ARB's Cap and Trade Program and will almost certainly have a detrimental effect on California's economy through harm to its import and logistics industries.

This study estimates that those combined program costs will cause a $2.22/gallon increase in the retail cost of diesel fuel, increasing retail costs by 50 percent to an estimated $6.69/gallon by 2020.

Higher California-only diesel prices will impose a significant burden on the California economy. Apart from their wider economic consequences, higher diesel prices will make California a less attractive destination for containerized imports from the Pacific Rim and reduce the economic benefits, employment, income and state and local taxes generated in California by that import trade.

The impact of higher retail diesel prices on containerized imports will be magnified by the competitive pressures on California ports due to the 2014 completion of the Panama Canal expansion project. The Panama Canal project will double the capacity of the canal and amplify by 50 percent containerized import losses caused by retail diesel price increases.

Between 2015 and 2020, the cumulative impacts of just those containerized import losses will be 616,922 lost jobs, $68.5 billion in lost state domestic product, $21.7 billion in lost income and $5.3 billion in lost state and local taxes.

By comparison California job losses due to the current recession between 2007 and 2010 were 1,304,600 jobs. The projected cumulative loss of 616,922 jobs, solely due to retail diesel price increases, would equal nearly half the state's total recession-related job losses.

Many of the job losses will be in the economically significant logistics industry, the industry responsible for almost 14 percent of the California economy, the industry groups responsible for the shipping, receiving, processing, and storage of goods, and an important source of middle-class entry jobs.

Costs associated with a Compliance Outcome will further isolate California from other states by increasing the cost of transportation, goods movement and amenities, and will have this impact without a corresponding direct public health benefit, unlike air quality policies that target criteria pollutants.

The other possible outcome is Non-Compliance, or infeasibility, which will occur if the fuels needed to achieve the program's objectives are not available at the times needed and/or in the qualities and quantities required.

At this time, based on available data, CTA expects that in the absence of timely action by ARB, a non-compliance outcome is highly likely and could appear as early as 2014. The costs of this outcome are more difficult to project, as they depend upon the future actions of market participants and the ARB.

Infeasibility is the almost inevitable consequence of an inherent flaw in the LCFS compliance framework. Each year the LCFS's declining annual carbon intensity target paradoxically lowers the credit-generating ability of renewable fuels to offset the increasing credit deficits of conventional fuels.

The possibility of compliance, therefore, would depend upon very large, albeit unlikely, improvements in the credit-generating ability of renewable alternatives. These very large carbon-intensity improvements, and the significant investments needed to make such improvements possible, would have to materialize in less than a decade.

The impacts of LCFS infeasibility are likely to appear in the cost of program credits in the 2014-2015 time frame. Scarce, high-priced program credits will threaten the price and availability of fuels, especially diesel fuel.

However, unchecked costs associated with the behavior of the LCFS credit market could quickly become very significant unless measures are undertaken to control them. Worse, the economic damage from these unchecked costs would occur without conferring any carbon emissions reductions.

ARB's apparent resistance to seriously considering the possibility or consequences of a non-compliance outcome, which by some estimates could begin to occur as soon as 2014, is of great concern.

The credit market structure so far created by ARB is woefully undeveloped and its slow pace of its future development appears to reflect ARB's view that non-compliance will be an unlikely event.

Should infeasibility become a reality, ARB's swift and considered intervention to mitigate high credit prices will become critical to safeguarding the California economy from widespread harm.

There is a need for greater legislative involvement in the ARB's GHG reduction programs. In particular, the Legislature should:

- Review and consider oversight options that ensure that the GHG reduction costs imposed by ARB programs are affordable. ARB's critical planning oversights, its concealment of potentially high diesel costs that would be imposed by the LCFS and Cap and Trade programs and concerns about ARB's potential unpreparedness to mitigate unchecked credit market shortages raise questions about continuing to support ARB's independent ability under AB 32 to impose significant costs on the California economy.
- Review the ARB's governance structure and consider strengthening it by empowering part-time board members with independent analytical resources and support capabilities so they can play a more effective role in policy decisions.
- Review whether it makes sense to continue to include diesel in the LCFS program. Diesel's LCFS contribution to GHG reduction is extremely small; yet, retaining diesel in the LCFS program could cause significant economic damage, including the loss of hundreds of thousands of jobs, by discouraging the import of containerized goods into California ports and by placing California-based logistics companies at an unreasonable competitive disadvantage in their traditional markets.
- Review requiring that LCFS and Cap and Trade program costs ARB imposes on refiners be imposed as tax-exempt, per-gallon surcharges in the same manner that other state and federal fees and excise taxes are currently posted and imposed. Tax-exempt surcharges would prevent regulatory costs from being amplified by being themselves taxed, would avoid the competitive effects of regulatory costs created by differences between companies and would bring greater transparency for the public and Legislature regarding the costs of ARB GHG reduction programs when program revenues are considered for future spending.

Glossary

AB 32 – California's 2006 greenhouse gas reduction law

Advanced Biofuel – An RFS2 fuel requirement category that can be met by blending a prescribed proportion of any alternative fuel, including sugar cane ethanol, cellulosic biofuels and biomass-based diesel but not corn starch ethanol, which reduce GHG emissions by at least 50 percent.

All-water service – A service offering of the steamship lines in which cargoes from Asia to eastern USA points transit the Panama Canal and utilize a port of entry on the East Coast or the Gulf Coast.

ARB – California Air Resources Board

Biomass-Based Diesel – An RFS2 fuel requirement category that can be met by blending a prescribed proportion of alternative diesel fuels, biodiesel and/or renewable diesel, which reduce GHG emissions by at least 50 percent.

Cap and Trade program – A program, authorized by AB 32 that caps the aggregate GHG emissions from covered entities responsible for 80 percent of the state's GHG emissions. The ARB will issue carbon allowances that these entities will be able to buy and sell. The number of allowances issued will be less than the amount of emissions that would otherwise be produced, thereby lowering overall emissions.

Cellulosic Biofuel – An RFS2 fuel requirement category that can be met by blending a prescribed proportion of cellulosic diesel fuels produced from cellulose, hemicellulose, or lignin, such as cellulosic ethanol, BTL diesel and cellulosic gasoline, which reduce GHG emissions by at least 60 percent.

CI – Carbon Intensity. A measure of the carbon content of a fuel in terms of the CO_2 emissions released by combustion of that fuel.

CTA – California Trucking Association

Drayage – A truck pickup from or delivery to a seaport, border point, inland port, or intermodal terminal.

EIA – U.S. Energy Information Administration

EISA – The Energy Independence and Security Act

EPA – U.S. Environmental Protection Agency

FAHC – Fatty Acids to Hydrocarbon. The hydrogenation process used to produce renewable diesel.

FAME – Fatty acid methyl esters, the product of transesterification, the manufacturing process which converts oils and fats into biodiesel.

FEU – Forty-foot Equivalent Container Unit

Fuel Surcharge – A charge imposed by trucking companies, based upon a weekly EIA index, that reflect the additional cost of retail fuel price increases.

GHG – Greenhouse Gas

LCFS – Low Carbon Fuel Standard

Logistics Industry – The logistics industry is made up of a variety of industry groups responsible for the shipping, receiving, processing, and storage of goods.

Long-run analysis – Assumes that infrastructure at other ports and channels serving those ports would be expanded as necessary to maintain current container flow times for increased shares of imports routed through those ports and channels.

MMTCO2E – Million metric tons of CO2 equivalent

MT – metric ton

Non-Obligated Parties – Providers of certain alternative fuels including: electricity, hydrogen and hydrogen blends, fossil CNG and LNG derived from North American sources, biogas CNG, and biogas LNG. Non-obligated providers of these fuels may opt-in to the program and become regulated parties.

Panama Canal project – A project to double the capacity of the canal by 2014, by allowing more and larger ships to transit

Regulated Parties – The fuel producers and importers legally responsible for the quality of various petroleum transportation fuels in California.

Renewable Biofuel – An RFS2 fuel requirement category that can be met by blending a prescribed proportion of ethanol derived from corn starch–or any other qualifying renewable fuel, which reduce GHG emissions by at least 20 percent.

Renewable Diesel – A diesel substitute manufactured by hydrogenating vegetable oils and animal fats.

RFS2 – The revised federal Renewable Fuel Standard program that was established in 2007 under the Energy Independence and Security Act.

RIMS – The Regional Input-Output Modeling System, developed by the U.S. Bureau of Economic Analysis, to estimate how the economy responds to changes in economic activity.

RIN Program – RIN stands for Renewable Information Number. An element of the RFS2 program which creates market incentives for refiners, manufacturers and importers of petroleum and alternative fuels to meet RFS2 program goals.

SCAG – Southern California Association of Governments

Short-run analysis – Predicts changes in import flows resulting from the imposition of a container fee assuming no changes in port and channel infrastructure or in staffing levels and operating schedules of the infrastructure.

Appendix A

Legal Challenge

Legal Challenge[73]

On December 29, 2011, a federal district court in California granted a preliminary injunction preventing the state from enforcing the LCFS. The lawsuit, filed by the ethanol industry, claimed that the LCFS violated the US Constitution's Commerce Clause. The Commerce Clause explicitly grants Congress authority to regulate commerce among the states and limits the power of the states to discriminate against or unduly burden interstate commerce.

The U.S. Supreme Court uses a two-tiered approach to Commerce Clause analysis. The first tier applies when a state statute or regulation "directly regulates or discriminates against" interstate commerce.   In such cases, the courts will apply a "strict scrutiny" analysis, and if found valid, will strike down the regulation without further inquiry.

The second tier is for cases where a state statute or regulation regulates in-state and out-of-state commerce equally and has only an indirect effect on interstate commerce. This test requires the courts to balance the burdens of a state rule against its purported benefits.

The federal district court held that California's LCFS treats Midwest corn-derived ethanol differently than similar California corn-derived ethanol. The LCFS assigns higher carbon intensity (CI) values to Midwest ethanol based on the plant's location because Midwest ethanol may be produced in plants that use more coal-based electricity than California-based plants. A higher CI value also reflects the fact that Midwest ethanol would need to travel farther to California than locally-made ethanol. Because the effect of these CI values would affect Midwest ethanol prices and market viability, the court found the LCFS discriminatory "on its face" under the "strict scrutiny" test.

The court further found that the LCFS sought to control conduct beyond the boundary of the state, an action precluded by the Commerce Clause. The court found that the LCFS's requirement that land use changes be considered in calculating carbon intensity regulates conduct that occurs almost entirely outside of California's boundaries.

Since California harvests only a fraction of the country's corn, the land use practices that the LCFS finds as GHG-unfriendly occur overwhelmingly outside that state. The court found this is an illegal attempt by California to extend its police powers beyond its borders.

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[73] *http://www.biofuelsdigest.com/bdigest/2011/12/30/us-federal-court-issues-injunction-against-california-low-carbon-fuel-standard/*

Because the court found that the LCFS violated the Commerce's clause strict scrutiny test, it found it unnecessary to address other aspects of the industry's Commerce Clause claims. It also decided not to address the plaintiffs' claim that the LCFS violated the 2007 EISA, and therefore the Constitution's Supremacy Clause, which invalidates state laws that interfere with or are contrary to federal law. The EISA specifically exempted existing corn ethanol producers from claiming or demonstrating GHG reductions.

At the moment, the decision doesn't establish legal precedent because it is at the district court level. However, the decision will almost undoubtedly be appealed all the way to the U.S. Supreme Court. In any case, the ruling will be closely scrutinized by other states and industries involved in disputes over the legitimacy of individual states' ability to regulate climate change emissions.

Appendix B

LCFS Compliance Schedules

Table B-1. LCFS Compliance Schedule for 2011 to 2020 for Gasoline and Fuels Used as a Substitute for Gasoline.

Year	Average Carbon Intensity (gCO2E/MJ)	% Reduction
2010	Reporting Only	
2011	95.61	0.25%
2012	95.37	0.5%
2013	96.42	1.0%
2014	95.93	1.5%
2015	94.95	2.5%
2016	93.98	3.5%
2017	92.52	5.0%
2018	91.06	6.5%
2019	89.60	8.0%
2020 and subsequent years	87.65	10.0%

Table B-2. LCFS Compliance Schedule for 2011 to 2020 for Diesel Fuel and Fuels Used as a Substitute for Diesel Fuel

Year	Average Carbon Intensity (gCO2E/MJ)	% Reduction
2010	Reporting Only	
2011	94.47	0.25%
2012	94.24	0.5%
2013	95.40	1.0%
2014	94.91	1.5%
2015	93.95	2.5%
2016	92.99	3.5%
2017	91.54	5.0%
2018	90.10	6.5%
2019	88.65	8.0%
2020 and subsequent years	86.72	10.0%

Appendix C

RFS2 Schedule

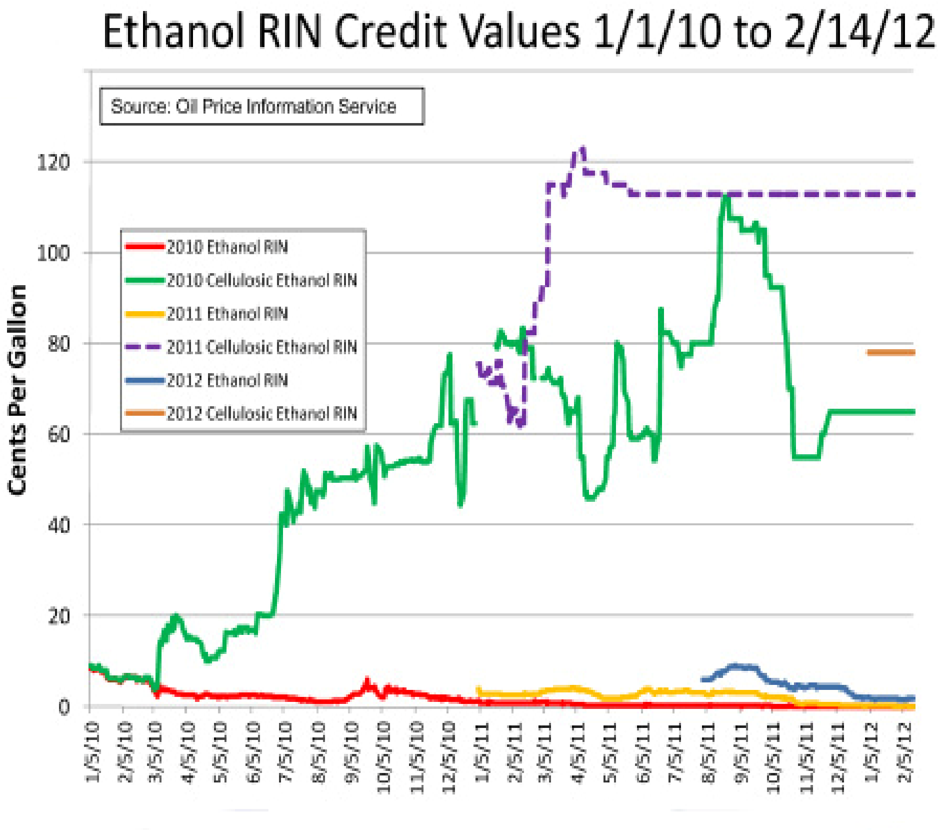
Renewable Fuels Standard (RFS2) - Current

Year	Total Renewable Fuel Requirement Bil. Gallons	Starch Derived Biofuel Bil. Gallons	Advanced Biofuels: Cellulosic Biofuels Bil. Gallons	Advanced Biofuels: Other Advanced Biofuels Bil. Gallons	Advanced Biofuels: Biomass Based Diesel Bil. Gallons	Advanced Biofuels: Total Advanced Biofuels Bil. Gallons
2008	9.00	9.00				0.00
2009	11.10	10.50		0.10	0.50	0.60
2010	12.95	12.00	~~0.10~~ 0.0065	~~0.20~~ 0.294	~~0.65~~ 1.15	0.95
2011	13.95	12.60	~~0.25~~ 0.0066	~~0.30~~ 0.543	0.80	1.35
2012	15.20	13.20	~~0.50~~ 0.0035 - 0.0126	~~0.50~~ 0.987 - 0.997	1.00	2.00
2013	16.55	13.80	1.00	0.75	~~1.00~~ 1.28	2.75
2014	18.15	14.40	1.75	1.00	1.00	3.75
2015	20.50	15.00	3.00	1.50	1.00	5.50
2016	22.25	15.00	4.25	2.00	1.00	7.25
2017	24.00	15.00	5.50	2.50	1.00	9.00
2018	26.00	15.00	7.00	3.00	1.00	11.00
2019	28.00	15.00	8.50	3.50	1.00	13.00
2020	30.00	15.00	10.50	3.50	1.00	15.00
2021	33.00	15.00	13.50	3.50	1.00	18.00
2022	36.00	15.00	16.00	4.00	1.00	21.00
2023	36.00	15.00	16.00	4.00	1.00	21.00
2024	36.00	15.00	16.00	4.00	1.00	21.00
2025	36.00	15.00	16.00	4.00	1.00	21.00
2026	36.00	15.00	16.00	4.00	1.00	21.00
2027	36.00	15.00	16.00	4.00	1.00	21.00
2028	36.00	15.00	16.00	4.00	1.00	21.00
2029	36.00	15.00	16.00	4.00	1.00	21.00
2030	36.00	15.00	16.00	4.00	1.00	21.00

Source: CEC Transportation Energy Workshop, November 14, 2011.

Appendix D

Historical RIN Prices



Source: CEC Recent Trends Overview February 14, 2012

Appendix E.

Infrastructure Costs Associated with LCFS Compliance

Infrastructure Costs Associated with LCFS Compliance

ARB staff used EPA's 2007 RFS regulatory impact analysis to estimate biofuel storage, transport, and distribution costs[74]. ARB staff also reviewed EPA's 2009 RFS2 Regulatory Impact Analysis, which updated the original 2007 study and pronounced it unchanged from the 2007 analysis.[75]

EPA's estimated storage, transport, and distribution costs for biodiesel were $0.22/gal in 2011 dollars, divided into $0.11/gal for infrastructure capital costs and $0.11/gal for freight transportation.

EPA's analysis of the costs associated with distributing the volumes of biofuel used under RFS2 included: 1) the capital cost of making the necessary upgrades to the fuel distribution infrastructure, and 2) the freight costs associated with shipping renewable fuels to the point where they would be blended with petroleum-based fuels for biodiesel used to meet the RFS2 standards. This included costs for rail cars, barges, tank trucks, storage tanks at terminals, blending and other miscellaneous equipment.

EPA capital cost information was developed through input from terminal operators, companies familiar with the installation of manifest rail receipt facilities, rail car manufacturers, and tank truck manufacturers.

Freight cost information was developed through a study by Oak Ridge National Laboratory, based upon detailed projections of which transportation modes and combination of modes were best suited for delivery to specific markets considering source and end use locations, the current configuration and projected evolution of the distribution system, and cost considerations for the different transportation modes.

In its scenario cost analysis, ARB included the EPA's estimated costs for storage, transport, and distribution in RFS2-related ethanol costs. However, for biodiesel and renewable diesel, ARB attributed the $0.22/gal storage, transport, and distribution costs to the LCFS.[76]

In order to confirm the order of magnitude of the EPA estimates, CTA conducted interviews with California oil companies to get their estimates on infrastructure costs. For those companies willing to share their information, EPA's capital cost estimates were larger than oil company estimates. No companies had developed freight cost estimates that they were willing to share.

[74] Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. April 2007. Regulatory Impact Analysis: Renewable Fuel Standard Program. EPA420-R-07-004.
[75] Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. February 2010. Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis. EPA-420-R-10-006.
[76] Low Carbon Fuel Standard 2011 Program Review Report, Final Draft December 8, 2011**,** page 110

Appendix F.

State Diesel Tax Differences

Table F-1 State Diesel fuel Tax excluding Federal Taxes[77]

State	Rate (Cents/gallon)
California	38.0
Nevada	27.7
Arizona	27.0
Utah	24.5
Oregon	30.0
Average Non California Fuel Tax	27.3
Net Average Difference: California vs. Neighboring States	10.7

[77] State Motor Fuel Tax Rates, Federation of Tax Administrators, January 2012.

Appendix G

Blue Collar Job Salary Comparisons and Educational Attainment

Table G-1. Blue Collar vs. Non-Blue Collar Jobs: Sectors and Average Annual Salaries

Sector	Average Annual Salaries
Blue Collar Jobs	
Mining	$65,268
Wholesale Trade	$51,156
Manufacturing	$47,933
Logistics	$45,851
Construction	$41,076
Blue Collar Job Alternatives	
Gaming	$37,827
Retail Trade	$28,824
Agriculture	$24,552
Hotel/Motel	$16,026
Food Service	$16,026

Source: Multi-County Goods Movement Action Plan, Technical Memorandum 5a – Economic Benefits and Costs of Growth In Goods Movement, Los Angeles County Metropolitan Transportation Authority, June 2007.

Table G-2. Educational Attainment of California Citizens 25 Years And Over

Less than 9th grade	10.4 percent
9th to 12th grade, no diploma	8.9 percent
High school graduate (includes equivalency)	21.5 percent
Some college, no degree	21.5 percent
Associate's degree	7.7 percent
Bachelor's degree	19.2 percent
Graduate or professional degree	10.8 percent

Source: American Community Survey, 2010