

Agenda Item A

Revised January 27th ~~Draft~~ Meeting Notes

Oregon Low Carbon Fuel Advisory Committee

Advisory Committee 3rd Meeting

January 27, 2010



State of Oregon
Department of
Environmental
Quality

Attendance

Advisory committee members and alternates

Mark Reeve, Chair - Reeve Kearns, PC
Emily Ackland - Association of Oregon Counties
Kyle L. Davis - PacifiCorp
Marie Dodds – AAA Oregon/Idaho
Robert Grott - Northwest Environmental Business Council
Sam Hartsfield - Port of Portland
Ian Hill - SeQuential Biofuels
Frank Holmes - Western States Petroleum Association
Brock Howell - Environment Oregon
Randy James - Portland and Western Railroad
Michael Johns - Lane County Department of Public Works
Christine Kelly - Oregon State University
Mark Kendall – Oregon Environmental Council
Dan Kirschner – Northwest Gas Association
Tom Koehler – Pacific Ethanol
Hollie Lund (afternoon) – Farm Bureau
Geoff McPherson - Citizen
Matt Michel - Canby Utility
Harrison Pettit – ZeaChem
Andrew Plambeck - Citizen
Joshua Proudfoot - Good Company
Marcy Putman - Labor Union – IBEW
Paul Romain (morning) – Oregon Petroleum Association/OPUDA
Danelle Romain (afternoon) - Oregon Petroleum Association/OPUDA
Bob Russell - Oregon Trucking Association
Jennifer Shmikler (morning) - Farm Bureau

Others in attendance

Michael Abendhoff - BP
Alan Branscomb - CES
David Collier - ODEQ
John Courtis – California Air Resources Board
Brian Doherty – Miller Nash/WSPA
Nick Economides - Chevron
Jana Gastellum – Oregon Environmental Council
Andy Ginsburg - ODEQ
Grant Kendall – Kendall Energy Consulting
Margi Lifsey - ODOT
Sue Langston – ODEQ
Dennis Moreland – Moreland Oil Company
Dave Nordberg - ODEQ
Uri Papish - ODEQ
Wendy Simons - ODEQ
Dwight Stevenson – Tesoro Corporation
Jeffrey Stocum - ODEQ
Rick Wallace – Oregon Department of Energy

Note: Where responses to questions or comments came from persons other than DEQ staff, the source is noted in parentheses, for example, **Response** (CARB).

Chair Mark Reeve welcomed attendees and called the third meeting of the Low Carbon Fuel Standard advisory committee to order at approximately 9:05 am.

Before addressing the official agenda items, Chair Reeve noted that Tom Koehler from Pacific Ethanol has joined the committee, while Harrison Pettit will continue on the committee in a new capacity, representing the advanced biofuels sector on behalf of ZeaChem, a company based in Colorado that is building a pilot plant in Boardman.

Chair Reeve called upon David Collier from DEQ to explain the changes that DEQ has made in its project timeline for the Low Carbon Fuel Standard rulemaking. DEQ plans to hold advisory committee meetings through November 2010, with a hiatus in July and August to allow for work by DEQ's contractor on the economic analysis. The committee will review draft LCFS rules at the November 2010 wrap-up meeting.

Chair Reeve also informed the committee about a change in procedure to allow petroleum industry representatives to contribute comments to the discussion directly. Company representatives will contact the Western States Petroleum Association representative who sits on the committee, who in turn will ask for recognition by the committee chair.

A request was made for a presentation at the next advisory committee meeting on recent lawsuits challenging California's Low Carbon Fuel Standard regulation.

A committee member commented that the LCFS is not focused on discouraging the use of fuel through conservation, nor on reducing vehicle emissions. Rather the LCFS is focused solely on lifecycle emissions from fuels. Another committee member noted that efforts are underway by groups in the state to address those other issues, and suggested that the advisory committee voice support for efforts to reduce vehicle emissions and vehicle miles travelled. Chair Reeve suggested that the decisions about which greenhouse gas reduction programs to pursue belong to the Legislature, and that the committee's focus should be making recommendations for a state LCFS. However, he supports giving individual committee members the opportunity to include comments about policy issues and other concerns in the committee's final report to the Environmental Quality Commission.

Agenda Item A - Review of December 3rd Draft Meeting Notes

Chair Reeve asked if attendees had any corrections to the December 3 Draft Meeting Notes.

The following corrections were suggested:

- At the top of Page 12, change the word "consensus" to something softer regarding the group's conclusion about regulated and opt-in fuels.
- Second bullet on Page 14 and seventh bullet on Page 15 should refer to B5 rather than B10 (B5 is the highest blend percentage that diesel truck engine manufacturers allow under warranties).

Agenda Item B – Low Carbon Fuel Credits and Deficits

Sue Langston of DEQ gave a presentation on calculating credits and deficits under the Low Carbon Fuel Standard program.

As Ms. Langston described some of the components of the calculation, which includes accounting for Energy Economy Ratios (EERs), the committee engaged in a discussion about EERs as part of the LCFS in general. Points raised during the discussion of EERs included:

- Isn't considering EERs adding conservation into the LCFS, which goes beyond considering carbon intensity of the fuel? **Response:** The EERs are intended to put different fuels on an even footing by taking into account the energy that gets to the wheels and moves the vehicle, not simply the amount of fuel energy in the tank. The LCFS rule would not try to change the efficiency of vehicles using any type of fuel, but to account for differences in drive train efficiency.
- How would the LCFS treat methanol if used in cars? **Response (PGE representative):** In this instance, carbon intensity would be based upon the life cycle emissions, but the EER for methanol would take into account that an internal combustion vehicle running on methanol would not go as far. However, methanol is used more efficiently in a fuel cell vehicle, so the FCV EER for methanol would be more favorable.
- What happens if the drive train efficiency of a class of vehicles improves over time – do we need to recalculate the EERs? Another dimension is how often the baseline will be updated, i.e. if drive train efficiency increases for gasoline, the baseline would need to be adjusted in order to preserve the technology-forcing nature of the LCFS with regard to fuels.
- Commenter is afraid the committee is confusing energy content of the fuel with the ultimate use of the fuel.
- Economic analysis should include changes to gas tax revenues due to the increase in numbers of electric vehicles.
- Did California build in periodic reviews of its EERs? **Response (CARB):** Yes, they plan to review and adjust EERs in the future as needed, due to technology evolution. EERs look at how far different vehicles travel with same amount of energy, which is necessary because the program is looking at GHG emissions generated by driving each vehicle. Drive train efficiencies must be considered in order to take into account the efficiency of various fuel-vehicle systems.
- But what really matters is how many gallons of gasoline are burned, since each gallon causes the same amount of CO2 emissions regardless of how efficient the vehicle is. **Response:** Volume of fuel is what we're concerned with ultimately, but the LCFS needs to put other fuels (natural gas and electricity, for example) on an even footing with gasoline and diesel, and those other fuels use different vehicles which use energy more or less efficiently than gasoline/diesel vehicles. We will have to readjust these efficiency factors over the course of the program as vehicle efficiencies change.
- Is it practical to consider a fleet portfolio approach for credits and deficits, for instance to account for the percent of plug-in hybrids versus electric vehicles? **Response:** Fleets will not be regulated parties under the LCFS.
- As diesel vehicles get more efficient, will that help toward meeting the LCFS? **Response (CARB):** It depends on how the program is structured. In California's case, gasoline alternatives are compared only to gasoline, while diesel alternatives are compared only to diesel. **Response:** The committee will address whether to set one or two baselines for Oregon this afternoon, and will take up the subject of how often to review the rule at a future meeting.

- LCFS is treating diesel differently than electricity. From these calculation examples, it looks like DEQ is assuming we will be setting two standards. If LCFS is only about the carbon content of fuels, then conservation should be left to another program. **Response:** HB 2186 specifically allows for drive train efficiencies. One versus two baselines is an important issue for debate, and the committee will discuss it.
- As the fleet gets more efficient over time, will it take pressure off the LCFS to deliver GHG reductions? The rising bar of vehicle efficiency could obviate the need to raise the bar for the LCFS. (This question was offered as something to consider at a future time.)
- Megajoules as a measurement unit reflects the generation of heat, which is different than energy applied to the wheels which is horsepower, signifying how many times the wheels turn.

After walking through an example of how credits and deficits would be calculated using PowerPoint, Ms. Langston presented a number of issues related to credits and deficits, listed below with notes on committee discussion following each issue.

Banking credits: DEQ proposed that regulated and opt-in parties be able to bank credits, with no expiration.

Points raised by the committee:

- Could unlimited banking of credits dilute the effect of the program in later years? Conversely, getting more GHG reductions early on is helpful for fighting climate change.
- It could become a political factor if a big credit surplus builds up.
- Under the Renewable Portfolio Standard, credit banking encouraged early wind investments and allowed investors to be nimble and manage risks.

Borrowing credits: DEQ proposed that regulated and opt-in parties not be allowed to “borrow” credits for fuel which has not already been produced.

Points raised by the committee:

- Is there any problem with a business-to-business agreement promising to sell future credits? **Response:** No, but credits for fuel not yet produced could not be used for compliance purposes.

Third Parties buying/selling credits: DEQ proposed that third parties (i.e., not having any compliance obligation) not be allowed to buy or sell credits.

Points raised by the committee:

- If the concern is high credit prices, then capping the price could be a better option because it will be difficult to define “third party.”
- It may not be legal to exclude third party participants, but a good alternative may be to not allow unlimited banking by parties without compliance obligations.
- There is also a risk that a regulated party could sit on a pile of credits (hoarding).
- Would 2015 sunset mean that credits would expire? **Response:** Yes.

- It would be useful to reframe the question: Is there any value to third party participation, and if so how should they be constrained?
- Potential regulated parties are very nervous about speculation.
- The rules could require registration of third parties.

Small/Large/Repeat deficits: DEQ proposed that regulated parties could “carry over” deficits smaller than 10 percent of their total deficits for the year, but that larger deficits would incur a penalty. Repeat deficits would not be allowed.

Points raised by the committee:

- SO2 market-based program lets parties buy credits after close of compliance period and before the compliance filing is due in order to “true up,” giving an extra couple of months to ensure they are not out of compliance. **Response (CARB):** This approach could add complexity to the LCFS credit accounting

Credits from other greenhouse gas programs: DEQ proposed that credits from other greenhouse gas reduction programs could not be imported into the LCFS program.

Points raised by the committee:

- Suggest that the rules don’t contain an absolute prohibition on credits from other programs, maybe say “not allowed at this time”
- Broadening sources of allowable credits could allow the program to achieve the maximum CO2 reduction possible.
- **Clarification (DEQ):** Oregon can’t control the terms of a Congressionally-passed program, but does have the choice about whether to allow offsets to be used within the LCFS program.
- Could credits be traded with California and Washington’s LCFS programs? **Response:** Yes, as long as same credits are not sold twice.
- What if a party from a non-LCFS state, e.g. Utah, wants to sell credits? **Response (CARB):** The importer of a low carbon fuel from outside the state would be a regulated party and would get credits. California is setting up a voluntary program for non-California facilities to register with them and submit carbon intensity information.
- Perhaps Oregon land use programs with impact on transportation emissions could generate LCFS credits in the future
- Oversight would be needed for multi-state trades to prevent double-counting

Federal RINs: DEQ proposed that the LCFS program would not use RINs for tracking because they don’t provide sufficient information about carbon intensity, and because several low carbon fuels do not have RINs.

Points raised by the committee:

- We should use whatever information we can from the RINs in order to make our administration simpler. **Response (CARB):** California requires RINs to be reported, and plans to use it to double-check the information submitted for compliance.

Fuels sold to exempt users: This topic will be addressed at a later committee meeting.

Railroads: This topic will be addressed when the committee revisits exemptions. However, there was some committee discussion of issues related to exemptions:

- Biodiesel blends are also an issue for warranties on other types of engines.
- *Clarification* (DEQ): Provisions outside of Oregon's rule will limit blend percentages for biofuels.
- Oregon could end up building a lot of complications and limits into the LCFS, making it difficult for regulated parties to comply and encouraging fuel shuffling between states.
- *Clarification* (CARB): California is looking to adopt standards for biodiesel and biodiesel blends. Some blends are causing increases in NOx emissions.
- Railroads fear price increases if their fuel distributors can't sell blends to them, but have to make up for it by buying additional credits. *Response:* This is one reason why the choice of who has the compliance obligation matters; in this case, higher up the distribution chain is better.

Credits accumulating during program deferral and exemption periods: DEQ proposed that regulated and opt-in parties could accumulate credits during deferral and exemption periods.

Points raised by the committee:

- Some concern about large amounts of banked credits building up in early years
- Concern about protecting investments made in low credit fuel production capacity
- Request for an illustration of how this would work in practice.

The discussion of Agenda Item B took longer than the time allotted on the meeting agenda, so Chair Reeve suggested the committee take a shorter lunch break and begin with Agenda Item C after lunch.

Agenda Item C – Phase-In of Compliance Schedule

Dave Nordberg of DEQ presented a hypothetical trajectory for Oregon's LCFS, along the lines of the trajectory used in California. In early years, the required carbon intensity reductions would be small, increasing gradually so that larger reductions would be required in later years of the program.

Points raised during and after the presentation included:

- Committee member requested that DEQ do some rough calculations about what this trajectory would mean for Oregon. *Response:* Yes, DEQ will do this. This agenda item is informational only. DEQ will bring a recommendation to the committee once we have considered compliance scenarios with volumes of different fuels.
- It looks like we're considering a similar trajectory to California. Is Oregon starting at the same place with regard to market penetration of alternative fuels as California? *Response:* The fuels assessment will help the committee consider what is reasonable and feasible with regard to expectations about low carbon fuel volumes. All of the

program elements interact with each other: exemptions and deferrals, compliance schedule. A deferral would push the compliance schedule back if our projections turn out to be unreasonable, for instance.

Update on Oregon Carbon Intensities

Svetlana Lazarev of DEQ presented the committee with an update on draft carbon intensity values for Oregon's petroleum fuels. The draft carbon intensity for unblended gasoline is 91.75 g CO₂e/MJ, while the draft CI for unblended diesel is 92.43 g CO₂e/MJ.

Points raised during and after the presentation included:

- How recent is the information on oilsands crude, and can we get more recent data? **Response:** The data used in this analysis is 2007 data from the federal Energy Information Administration (EIA). 2008 data will be available in summer of 2010, but more recent data would have to come from private sources.
- Electricity source data as presented is misleading. Committee member can provide DEQ with more detailed information on the source mix for individual utilities, so that refinery electricity information will be more accurate. **Response (CARB):** California looked at refineries as a sector, rather than individually, when calculating that portion of petroleum carbon intensities. If they are disaggregated for electricity sources, then they would need to be disaggregated for other aspects as well. California used averages for initial calculations, but may reconsider this decision in the future.
- How often will carbon intensities be updated? **Response:** This is a topic for a future advisory committee discussion. **Response (CARB):** California will review every three years. They are developing a methodology for how to deal with new high carbon intensity crudes coming into California, and are in the process of forming a workgroup. The threshold: (1) more than two percent higher than how much came into the state in 2006, and (2) over 15 g CO₂e/MJ for production and transport.
- What if it's not a new high carbon intensity crude source, but a greater percentage of the mix than previously? **Response (CARB):** They are still working on this question.
- How are crudes tracked in Washington vs. California? **Response (WSPA):** California's Energy Commission monitors crudes used in California and has extensive, as well as more up-to-date, data. Washington relies upon the federal EIA data, with a delay in availability. WSPA has submitted studies on oilsands' carbon intensity, which DEQ has posted for committee members.
- Lag in numbers is concerning. What data will determine compliance with the program targets? **Response:** DEQ will need to track the numbers over time to see if the crude mix has changed significantly from what it was when the baseline was set, to ensure that carbon intensity increases in the base fuel don't outweigh the benefits from alternative fuels under the program. DEQ will be able to track this from compliance reports, which will be more up-to-date than EIA reports.
- Why doesn't DEQ require petroleum companies to report their crude sources and volumes as part of LCFS compliance? **Response (WSPA):** That would present antitrust problems as well as confidentiality issues. Information currently reported is filtered and consolidated to account for these concerns. **Response:** DEQ will track

information on oilsands and other factors that are most likely to make a significant impact on carbon intensity over time.

Agenda Item D – Setting the Baseline Standard

Wendy Simons of DEQ presented information about setting a baseline low carbon fuel standard. The decisions to be made relate to: (1) which data to use, and (2) should there be one or two standards. Data issues include which year's data to use (DEQ proposes to use 2007 EIA data, adjusted by applying the mandated biofuels blend percentages for 2010), and how to account for uncertainties about the actual percentage of ethanol and biodiesel that will be blended into transportation fuels statewide. DEQ proposes not to include electricity, CNG, LNG, hydrogen, and biofuels above the mandated blend percentage in the baseline calculation, as they would have a very small effect. DEQ presented two options for how many baselines to set: Option A – one baseline using a weighted average of gasoline and diesel; and Option B – two baselines, one for gasoline and one for diesel.

Points raised during and after the presentation included:

- The 2007 data is fine to start with and for DEQ to use for its analysis, and the EIA data is widely reported although not perfect. As we get closer to developing the rule, we can see if 2008 data are significantly different than 2007.
- Why not use 2008 data if it's available in July? **Response:** DEQ and its contractor need to go ahead with compliance scenarios and economic analysis before then.
- Considering 2007 versus 2008: In 2007 the economy was strong, so demand for oilsands as the marginal, most expensive resource, should be higher than in 2008 when the economy was weak. That would make 2007 a conservative baseline with regard to carbon intensity.
- Do we give fuel providers credit for blending ethanol into premium gasoline, if it's considered "exempt" from the state RFS?
- Does California have a state biodiesel mandate? **Response (CARB):** No, but California did project that 2020 fuels would contain the percentages of biofuels required under the federal RFS2.
- Commenter prefers not to include biodiesel in the baseline. Biodiesel blending was not required under state law in 2007, which is the year we're likely use for our baseline data. Would like to get credit for what we've already done. **Response:** We should include biodiesel at the 2010 required blend rates if we're trying to reflect what will actually be in the market in 2010, which includes B2 statewide and B5 in Portland (Portland reports sales of 15 percent of state diesel market).
- We shouldn't simply reward existing performance.
- The legislation says 2010, not 2007. Conversation ensued about how to interpret the date set in statute, whether it simply refers to the start of the program or to the actual data that must be used to set the baseline.
- Perhaps the program should require zero reductions until 2010 data is available, or should make it clear that ultimately regulated parties will have to true up to a baseline based upon 2010 numbers. **Response:** We have to start somewhere, and 2007 is what's available now. **Response (CARB):** California was directed by statute to use 2006 data for baseline, but the program required them to set a baseline for 2010. They had to make

assumptions about the 2010 fuel supply, using information about the federal RFS2 and state laws about biofuel blending requirements.

- Will the baseline be used to figure out what regulated parties have to do year-by-year, or simply to set the 2020 goal? If the baseline is used to set the 2020 goal, then making midterm adjustments once 2010 data is available is not as big a deal.
- It seems like we're talking about really small changes, while indirect land use change is going to dominate over the difference between 2007 and 2010.
- It makes sense to leave out small volume fuels when setting the baseline (for example, electric cars, blends over B5, etc.).
- Fuel-switching almost guarantees a new vehicle, and new diesel controls are stricter, so not that worried about increased diesel particulate pollution. Don't want to encourage dog fight over natural gas supplies between transportation and electricity generation.
- Commenter prefers one standard, and agrees that co-pollutants from diesel are not an issue. Light duty diesel is an improvement over gasoline.
- Oil industry prefers one standard, based upon new numbers from CARB on carbon intensity of soy biodiesel which is not much better than petro diesel.
- Commenter does not get the point of two standards, concerned about creating silos.
Response (CARB): If you have one standard, then once you take into account efficiency of diesel vehicles, regular diesel will generate credits without doing anything to improve its carbon intensity. Those credits could be applied toward gasoline, and gasoline would not have to make many improvements either. If there are two standards, improvements will have to be made on each side. Credits from each can still be applied toward compliance for the other fuel category. Acknowledges there are concerns about the lack of enough low carbon diesel alternatives. Even if the carbon intensities for gasoline and diesel are the same, if you apply an EER to diesel, then regular diesel will comply with the LCFS and you will get zero reductions from the program.
- Biggest contribution of the LCFS is stimulating innovation in the fuels market, so we want to make sure the program we design does that.
- Are electric vehicles under gasoline or diesel? Concerned about vehicles that are not easy to categorize, like certain pickups. **Response (CARB):** If the vehicles replace gasoline vehicles, then they are compared with gasoline, and vice versa. Credits from heavy duty fleets will be applied against diesel.
- Does the statute allow for two standards, differentiating between gasoline and diesel?
Response: We can check with DOJ later in the process, if it seems to be a relevant issue.
- We have high benzene content in our gasoline, so switching to diesel is not a big concern.
- In order to evaluate the importance of flexibility, it will be easier to understand if we had a couple of draft scenarios, even if they are rough.
- Carbon intensity of soy biodiesel is a big compliance concern for oil industry.
- Oil industry representative stated that diesel vehicles travel approximately 30 percent farther for the amount of carbon emissions generated.
- Switching more of the light duty fleet to diesel would have an immediate effect on carbon emissions. Reducing emissions in the short run is more valuable than in the long term. Two standards will delay the reduction in emissions, which makes the reductions worth less.

- How will electricity providers track when electricity is used to displace gasoline and when it displaces diesel? It would be easier for them to have one standard.
- Andy Ginsburg pointed out that Oregon is much smaller than California, and has much less chance of stimulating innovation in fuels, so perhaps other factors, such as avoiding complexity, should drive Oregon’s decision about one versus two standards.
- Commenter expressed preference for two standards, but sees that benefits will also come from one standard.
- Commenter expressed concern that one standard will allow credits for what regulated parties are already doing, causing lower benefit from the program. **Response:** Baseline could be set to ensure that there is no credit for existing diesels, only for new users of diesel. **Response (CARB):** Some people suggested that higher targets be set along with a single standard, like 14-15 percent, to compensate for regular diesel being already compliant. CARB is also concerned about setting a direction for beyond 2020 – if innovations don’t start to happen before 2020 in diesel alternatives, it will be more difficult to meet even deeper reductions in the long-term. This is a key concern driving CARB’s decision to set two standards.
- Andy Ginsburg asked whether committee was comfortable with a tentative consensus that they preferred one standard, but with plans to re-examine the issue once they have seen compliance scenarios.

Public comment

There were no requests to give public comment.

Agenda Item E – New Fuel Pathways

As the meeting was running behind schedule, Agenda Item E was skipped in favor of Agenda Item F. The New Fuel Pathways discussion will be scheduled for a future committee meeting.

A committee member pointed out that a few of the members will likely be absent from the February meeting due to the Legislative session, and expressed wishes that DEQ will take that into account when scheduling topics for that meeting.

Agenda Item F – Regulated and Opt-In Parties

Sue Langston of DEQ presented information about the distribution systems for various transportation fuels and the parties that could possibly be held responsible for complying with the LCFS, including those entities providing low carbon fuels which may have the option of participating in order to sell credits. The intention of the presentation was to give the committee background information for a full discussion at the next advisory committee meeting.

Points raised during and after the presentation included:

- CNG is a currently-existing technology, useful for short “captive” fleets that travel short distances, but economically marginal at this time. The LCFS could tip the scales in favor of making it economically feasible.
- Natural gas utilities are considering ideas to make home compressors more widespread, like leasing them to homeowners.

- Natural gas world has changed drastically over the last 12 months, with many new discoveries. Heavy-duty vehicle fleet owners are especially interested.
- Most common use of LNG is forklifts. They would most likely liquefy pipeline gas onsite. LNG gives vehicles more range.
- California's LNG filling stations were developed as a network for long-range trucking fleets, tied to the port of Los Angeles. The effort was led by a California clean air agency.
- The equipment is the same as for fossil fuel natural gas, although there could be extra steps to clean it to ensure there are no equipment problems. It's more difficult to clean methane that comes from municipal solid waste and sewage, compared to dairy manure. Most of this methane is used for electricity generation now. The LCFS could tip the scales in favor of making these kinds of projects more feasible.
- What is included when calculating the carbon intensity of methane from waste? Where are the boundaries drawn? **Response:** The committee will consider this at a later meeting.
- A lot of biogas CNG is getting "locked up" for electricity generation in order to comply with the state Renewable Portfolio Standard.
- Committee members discussed the carbon intensity of hydrogen which is generated from different sources of natural gas or biogas. EERs would be an important factor in this case, since fuel cell vehicles are more efficient than internal combustion engines. How would the producer of the natural gas know how it is eventually used in a vehicle (i.e., as CNG or hydrogen)? This will not be an issue until hydrogen is actually used as a transportation fuel in Oregon.
- Is there an easy way of netting out fuels that come to Portland terminal, and then are barged to Pasco? **Response (Trucking Association representative):** State economist has a study of fuels bought and used in Oregon and Washington. Perhaps the designation of regulated parties can piggyback onto the fuel tax system. Commenter believes that out-of-state distributors selling fuel into Oregon pay Oregon fuel tax. **Response:** DEQ LCFS team will coordinate with current greenhouse gas reporting rulemaking team to try to make reporting for LCFS and GHGs coincide where possible.
- How it would be handled if a distributor has retail stations on either side of the state borders? **Response:** If Washington and Oregon have similar programs, then we can coordinate.
- Does this proposal track with federal "Blenders of Record" designation? **Response (WSPA):** "Blender of record" refers to producer. For EPA reporting purposes, the refinery reports. That is the level where WSPA prefers reporting to be.
- If one regulated party sells fuel to another regulated party, the credits/deficits would automatically transfer? **Response (CARB):** It depends upon the agreement between the parties – terminals could decide to keep credits/deficits, rather than transfer the compliance obligation. Both parties would have to report, however.

- In case of a retail station getting shipments from out of state, the retail station would be a regulated party? **Response:** This issue has come up for GHG reporting as well. The volume of fuel involved is very small, but some fuel does arrive in Oregon this way. We want to try to make this as simple as possible for small businesses – perhaps an out-of-state distributor could voluntarily agree to be the regulated party in order to make it easier for the Oregon gas stations they distribute to.
- Where the biofuel producer is selling to a terminal, it seems likely that the compliance obligation would shift to the terminal, but that the terminal would pay a premium for the biofuel depending on its carbon intensity in order to get the credits. **Response:** This is correct. However, the biofuel producer would still need to report.
- Why are we considering forcing LNG to be regulated while CNG isn't, since CNG has a much bigger volume used in transportation? **Response:** We'll check into that. Perhaps volume will be so small for LNG that it should be opt-in.
- Why is non-North American natural gas treated differently? **Response:** We know that North American natural gas has a low carbon footprint, but non-North American natural gas most likely arrives by tanker, meaning it will be liquefied and then re-gasified, which raises its carbon intensity.
- It's possible that someone could deal in LNG, trucking it around to sell as a fuel. Or a fleet owner could liquefy it themselves. In any event, the volumes are likely to be small.

Comment from committee member: Washington has moved back the deadline for its report on a possible low carbon fuel standard from July of this year to November.

The meeting adjourned at approximately 4:05 pm.